Authority to Construct (ATC) Permit Application and Supplemental Information for the Prevention of Significant Deterioration (PSD) Permit Application

Amended Application for Certification for HYDROGEN ENERGY CALIFORNIA (08-AFC-8A) Kern County, California

Prepared for:
Hydrogen Energy California LLC

hydrogen energy california

Submitted to:
San Joaquin Valley Air Pollution Control District

U.S. Environmental Protection Agency Region IX

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Prepared by:
URS

May 2012

AUTHORITY TO CONSTRUCT (ATC) PERMIT APPLICATION

and

SUPPLEMENTAL INFORMATION

for the

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT APPLICATION

HYDROGEN ENERGY CALIFORNIA (HECA) PROJECT

Prepared for:

San Joaquin Valley Air Pollution Control District
U.S. Environmental Protection Agency Region IX

Prepared on behalf of:

Hydrogen Energy California LLC

URS

May 2012

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Acronyms

AAQS	Ambient Air Quality Standards
AB	Assembly Bill
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
AGR	acid gas removal
APCO	Air Pollution Control Officer
APN	Assessor's Parcel Number
AQMP	Air Quality Management Plan
AQRV	Air quality related values
ASU	air separation unit
ATC	Authority to construct
BACT	Best available control technology
BPIP-Prime	Building Parameter Input Program – Prime
Btu	British thermal units
BVWSD	Buena Vista Water Storage District
°C	degrees Celsius
CAA	Clean Air Act (Federal)
CAAA	Clean Air Act Amendments of 1990
CAAQS	California Ambient Air Quality Standards
CAISO	California Independent System Operator
CAPCOA	California Air Pollution Control Officers Association
CARB	California Air Resources Board
CCAR	California Climate Action Registry
CCW	Closed cooling water
CEC	California Energy Commission
CEMS	Continuous Emissions Monitoring System
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COS	Carbonyl sulfide
CTG	combustion turbine generator
DOC	Determination of compliance
DPM	Diesel particulate matter
EGU	Electric generating unit
EHOF	Elk Hills Oil Field
EOR	enhanced oil recovery
ERC	emissions reduction credits

°F	degrees Fahrenheit
FLAG	Federal Land Managers' Air Quality Related Values Workgroup
GAC	Granular-activated carbon
GEP	Good Engineering Practices
GHG	Greenhouse gas
gpm	gallons per minute
gr/dscf	grain per dry standard cubic foot
H_2	hydrogen
H_2O	Water
H_2s	Hydrogen sulfide
HAP	hazardous air pollutant
HARP	Hotspots analysis and reporting program
HECA	Hydrogen Energy California (or Applicant)
HHV	higher heating value
HNO_3	Nitric acid
HP	high pressure
HRA	Health risk assessment
HRSG	heat recovery steam generator
Hz	Hertz
IGC	Industrial Gas Company
IGCC	Integrated Gasification Combined Cycle
IGV	inlet guide vane
ISCST3	Industrial Source Complex Short Term 3rd version
ISO	International Standards Organization
KO	Knock out
kpph	Kilopounds per hour
kV	kilovolt
kW	kilowatt
lb/ft^3	Pounds per cubic foot
LDAR	Leak detection and repair
LORS	Laws, ordinances, regulations, and standards
LOX	liquid oxygen
LP	low pressure
LTGC	low temperature gas cooling
LV	Low Voltage
MEIR	Maximally exposed individual resident
MEIW	Maximally exposed individual worker
mg/kg	Milligrams per kilogram
$\mu g/m^3$	micrograms per cubic meter
MHI	Mitsubishi Heavy Industries
MMBtu	million British thermal units
msl	Mean sea level

MV	Medium voltage
MW	megawatt
N_2O	Nitrous oxide
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_2-CO-NH_2	Urea
NH_3	Ammonia
NH_4NO_3	Ammonium nitrate
NO	Nitric oxide
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New source review
O_2	oxygen
O_3	ozone
OEHHA	Office of Environmental Health Hazard Assessment
OEHI	Occidental of Elk Hills, Inc.
OLM	ozone limiting method
Pb	lead
PDC	Power Distribution Center
Petcoke	Petroleum and coke
PG&E	Pacific Gas and Electric Company
PM	Particulate matter
PM_{10}	particulate matter less than 10 μm in diameter
$PM_{2.5}$	particulate matter less than 2.5 μm in diameter
ppb	parts per billion
ppm	parts per million
ppmv	parts per million by volume
ppmvd	parts per million volumetric dry
PSA	Pressure Swing Adsorption
PSD	Prevention of significant deterioration
psia	Pounds per square inch absolute
PTO	Permit to Operate
PVMRM	Plume Volume Molar Ratio Method
Q/d	sum of the annualized daily emissions of PM10, NO2, SO2, and H2SO4 divided by the distance to the nearest Class I Area
REL	Reference Exposure Level
RPM	revolutions per minute
SB	Senate Bill
scf	Standard cubic foot

SCR	Selective catalytic reduction
SF_6	Sulfur hexafluoride
SIL	Significant impact level
SIPs	State Implementation Plans
SJVAPCD	San Joaquin Valley Air Pollution Control District
SJVRR	San Joaquin Valley Railroad
SMC	Significant Monitoring Concentrations
SO_2	Sulfur dioxide
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SO_X	sulfur oxide
SRU	sulfur recovery unit
STG	steam turbine generator
stpd	Short tons per day
stpy	Short tons per year
SWS	Sour Water Stripper
Syngas	Synthesis gas
TAC	toxic air contaminants
TDS	total dissolved solids
TGTU	tail gas treating unit
THI	total hazard index
tpy	tons per year
UAN	Urea ammonium nitrate
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
V	volt
VOCs	volatile organic compounds
WGS	Water-gas shift

This is the application by Hydrogen Energy California LLC (HECA LLC) to San Joaquin Valley Air Pollution Control District (SJVAPCD) for an Authority to Construct (ATC) permit. This application also contains supplemental information for the Prevention of Significant Deterioration (PSD) permit application previously submitted on June 26, 2009, to United States Environmental Protection Agency (USEPA) Region IX.

This application is for an Integrated Gasification Combined-Cycle (IGCC) polygeneration project (hereafter referred to as HECA or the Project). The HECA site is located in western Kern County, 1.5 miles northwest of the unincorporated community of Tupman, and about 7 miles west of the outermost edge of the City of Bakersfield. As described in this application, the proposed Project will be classified as a Major facility, as this term is defined in District Rule 2201; and a Major Stationary Source under the federal PSD rules.

Applications for previous designs of the Project have already been processed by SJVAPCD. On December 16, 2010, SJVAPCD issued the Final Determination of Compliance for the previous design of the Project, indicating that the Project met all the requirements of an ATC permit for a project reviewed under the California Energy Commission (CEC) licensing process. In September 2011, SCS Energy California LLC acquired 100 percent ownership of HECA LLC. HECA LLC has modified the Project design to ensure economic viability, and better serve market needs, while continuing to adhere to the strictest environmental standards. Under SJVAPCD rules, a completely new ATC application must be submitted as a result of the change in Project ownership. Accordingly, this application reflects the modified Project design, addresses all of the ATC requirements pursuant to the District's rules, and supersedes all application materials related to the Project that have been submitted to SJVAPCD by the previous applicant.

This application also supplements the information contained in the previous PSD application to USEPA in June 2009. Project emissions of certain pollutants will exceed federal PSD thresholds; accordingly, this application includes all materials necessary to meet the PSD requirements, in addition to those of the SJVAPCD. Completed copies of the SJVAPCD forms that are relevant to the HECA Project are included in Appendix A, SJVAPCD Application Forms. A check covering the District's application filing fees accompanies this application.

The Project will gasify a 75 percent coal and 25 percent petroleum coke (petcoke) fuel blend to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, which will be used to generate low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based products in an integrated Manufacturing Complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR) at a neighboring oil production field.

HECA will employ the most stringent emissions control equipment available for the types of processes and equipment that will comprise the Project, and will fully offset its emissions of nonattainment pollutants and their precursors. In addition, the Project's methods for production of electric power and nitrogen-based products will have a significantly lower carbon footprint than would be possible using traditional processes based on fossil fuel. This low-carbon footprint is accomplished by capturing more than 90 percent of the carbon in the syngas and transporting it as CO_2 for use in EOR, which results in simultaneous sequestration of this gas

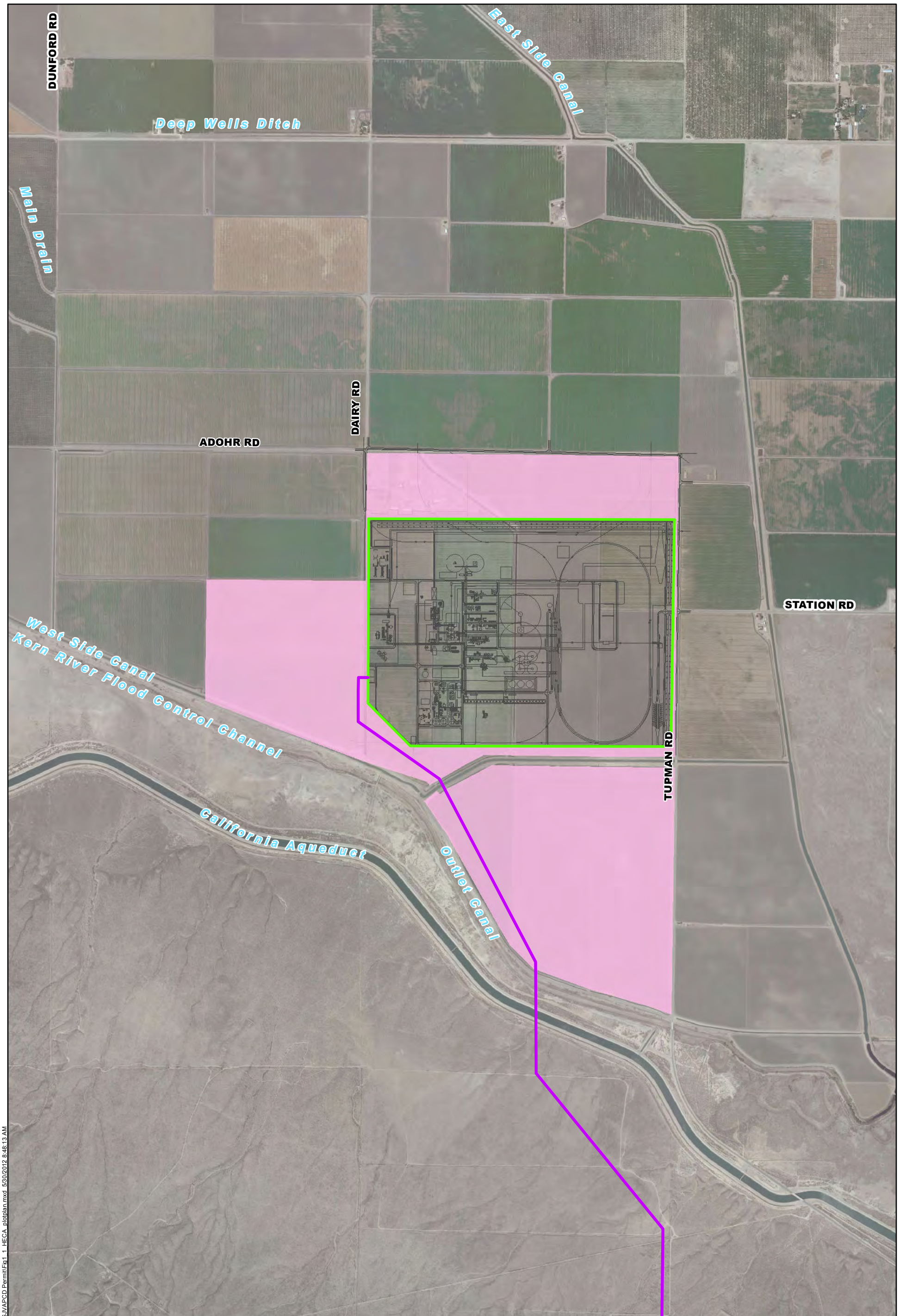
stream in a secure geological formation. The location of this sequestration will be the adjacent Elk Hills Oil Field (EHOF), which is owned and operated by Occidental of Elk Hills, Inc. (OEHI). The OEHI EOR Project will be separately permitted by OEHI through the Department of Conservation, Division of Oil, Gas, and Geothermal Resources, and SJVAPCD. Accordingly, equipment and emissions associated with EOR at the OEHI site are not addressed in this application.

1.1 OVERVIEW

The HECA Project will be located near the unincorporated community of Tupman in western Kern County, California, as shown on Figure 1-1, Project Site Plan and Vicinity.

Key elements of the Project are summarized below:

- The Project is designed to operate on a fuel blend consisting of 75 percent western sub-bituminous coal and 25 percent California petcoke for the life of the Project, as measured by thermal input to the gasifier on a higher heating value (HHV) basis.
- The feedstock fuels will be gasified to produce syngas that will be further processed and cleaned in the Gasification Block to produce hydrogen-rich fuel.
- More than 90 percent of the carbon in the raw syngas will be captured in a high-purity CO_2 stream that will be compressed and transported by pipeline to the EHOF for injection into deep underground hydrocarbon reservoirs for EOR.
- Capture and sequestration of carbon from the syngas will significantly reduce the Project's emissions of greenhouse gases (GHGs) compared with comparable power generation from fossil fuel combustion, and chemical production processes based on fossil fuel.
- The Combined Cycle Power Block will generate approximately 405 megawatts (MW) of gross power and will provide a nominal 300 MW of low-carbon baseload electricity to the grid during operations. The remaining power generation will be used on-site to meet the facility's internal loads in the Gasification Block, and routed to the Manufacturing Complex for use in nitrogen-based product manufacturing.
- An integrated Manufacturing Complex will produce approximately 1 million tons per year of low-carbon nitrogen-based products, including urea, urea ammonium nitrate (UAN), and anhydrous ammonia for use in agricultural, transportation, and industrial applications.
- The power and nitrogen-based products produced by the Project will have a significantly lower carbon emission profile relative to similar power and products traditionally generated from fossil fuels, such as natural gas or coal. Natural gas is the fuel source used predominantly for power generation in California.
- The Sulfur Recovery Unit (SRU) will convert sulfur compounds into a saleable sulfur product.



Project Site
Controlled Area
Carbon Dioxide Pipeline

N

0 750 1,500 FEET

PROJECT SITE PLAN AND VICINITY

May 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1-1

Source: Aerial Photo, Digital Globe, 2008.

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- The Project is designed with state-of-the-art emission control technology to minimize air emissions through the use of Best Available Control Technology (BACT) for both criteria air pollutants and GHGs. In addition, emissions of nonattainment pollutants and their precursors will be offset by means of emission reduction credits (ERCs).

- The Project is designed to avoid flaring during steady-state operation, and to minimize flaring during start-up and shut-down operations.

For the purposes of all air quality analyses described in this application, impacts were evaluated for locations outside of both the 453-acre Project Site and a Controlled Area consisting of 653 acres of land extending beyond the Project Site. Boundaries of both areas are shown on Figure 1-1, Project Site Plan and Vicinity. The purpose of the Controlled Area is to ensure ownership and control by HECA LLC over public access and land use adjacent to the Project Site. Current plans are to continue to use the Controlled Area primarily for agricultural purposes during construction and operations.

Figure 1-2, HECA Plot Plan with Emission Source Locations, shows the layout of Project process areas, equipment, and emission sources within the proposed site. These include:

- Solids handling, gasification, and gas treatment:
  - Feedstock delivery, handling, and storage
  - Gasification Unit
  - Sour Shift/Removal units
  - Acid Gas Removal (AGR) Unit
  - SRU/Gas Compression
  - CO_2 compression

- Power generation:
  - Combined Cycle Power Block equipment
  - Electrical equipment and systems

- Manufacturing Complex:
  - Pressure Swing Adsorption (PSA) Unit
  - Ammonia Synthesis Unit
  - CO_2 compression and purification (for urea production)
  - Urea Unit
  - Urea Pastillation Unit
  - UAN Complex (includes Nitric Acid Unit, Ammonium Nitrate Unit, and Urea Ammonium Nitrate Unit)

- Supporting process systems:
  - Natural gas fuel systems
  - Air Separation Unit (ASU)
  - Sour water treatment

  - Wastewater treatment for process and plant wastewater streams
  - Raw water treatment plant for process water

- Other plant systems (i.e., heat rejection systems, auxiliary boiler, flares, emergency engines, fire protection, plant instrumentation, and air emission monitoring systems)

Details of the emissions increases as a result of the on-site Project components and offsets are discussed in Section 3 and Section 7, respectively. The proposed Project will trigger BACT requirements for nitrogen oxides (NO_X), sulfur oxides (SO_X), volatile organic compounds (VOCs), particulate matter (PM), and carbon monoxide (CO). Sections 3.2 and 3.3 describe the BACT analyses, and proposed technologies that will be included to meet BACT as proposed in this application, based on the most current industry data and manufacturers' information.

Dispersion modeling was conducted to determine the potential impacts of criteria pollutant and hazardous air pollutant (HAP) emissions. The impacts from the Project will not exceed any of the State or Federal Ambient Air Quality Standards (AAQS). However, the Project will trigger PSD Review. Section 4 details the AAQS standards and the PSD analysis. The Project will not cause any exceedance of PSD-significant ground level concentrations. Analyses for Class I Areas and air quality related values (AQRV) are presented in Section 6 as part of the PSD review. The modeled health risk of toxic air emission increases are below significance levels, as discussed in Section 5.

1.2 APPLICANT AND PROPOSED PROJECT INFORMATION

1.2.1 Business Name/Location

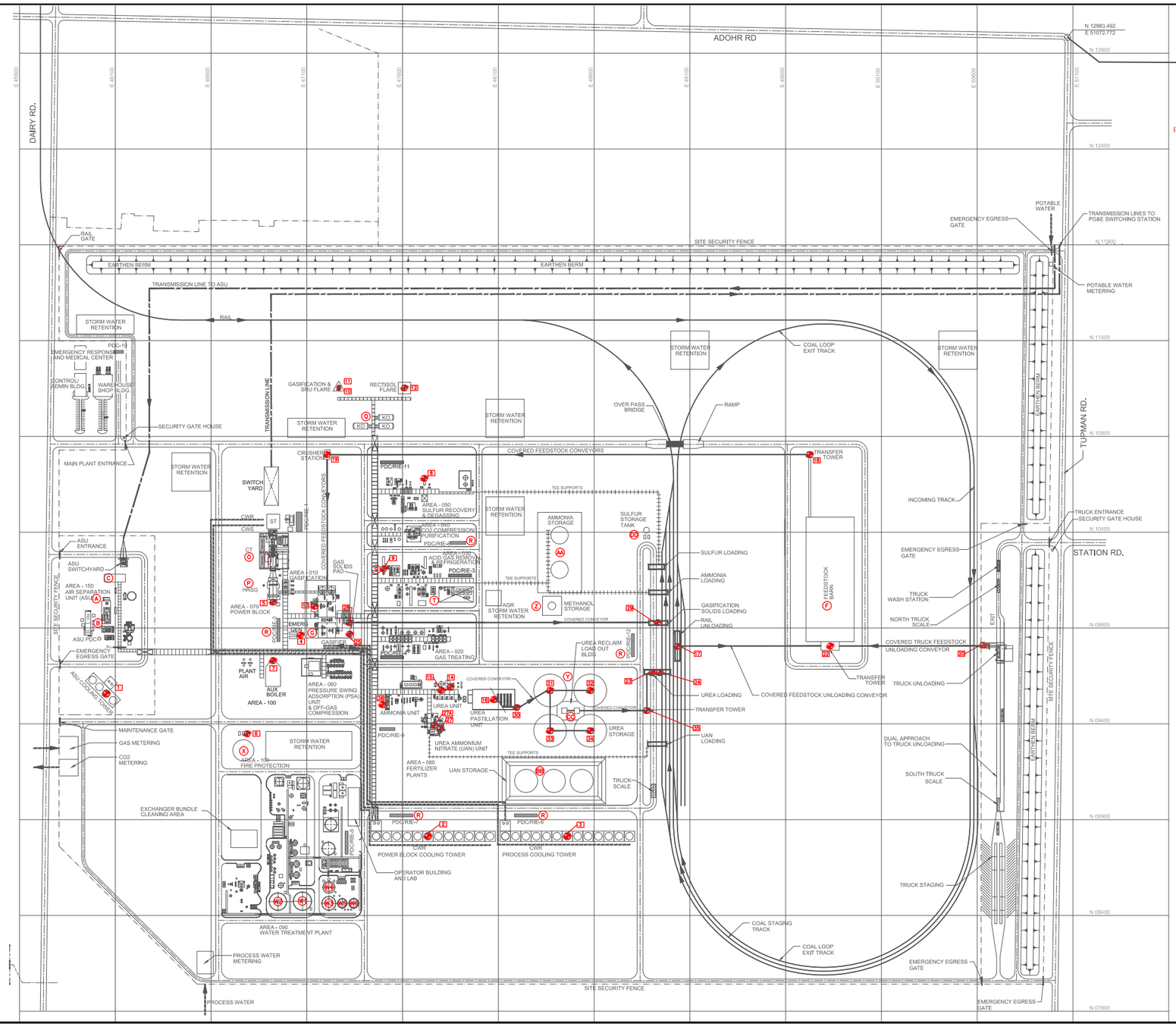
The Project will be owned and operated by Hydrogen Energy California LLC(HECA LLC), which is wholly owned by SCS Energy California LLC.

The Project will be approximately 7 miles west of the outermost edge of the City of Bakersfield, and 1.5 miles northwest of the unincorporated community of Tupman in western Kern County, California. The legal description is as follows: Section 10 of Township 30 South, Range 24 East, in Kern County. The associated Assessor's Parcel Numbers (APNs) are the following:

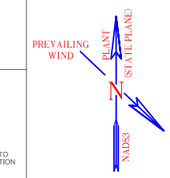
- Part of 159-040-02,
- Part of 159-040-16, and
- Part of 159-040-18.

HECA is also acquiring an additional 653 acres of land adjacent to the Project Site, herein referred to as "Controlled Area." HECA LLC will own this property, and have control over public access and future land use. For the purposes of the Air Quality analysis, impacts were determined outside of both the Project Site and the Controlled Area. The associated APNs of the Controlled Area are:

- 159-040-04,
- 159-040-11,
- 159-040-17,
- 159-190-09,
- Remnant part of 159-040-02,
- Remnant part of 159-040-16, and
- Remnant part of 159-040-18.



DWA #20001: (CALCULATED)	NORTHING	EASTING
STATE PLANE COORD.	2312983.492	6151072.772
NAD83 ZONE V (U.S. FEET)		
LATITUDE: 35°20'25.11200"	LONGITUDE: 119°22'36.21665"	
LATITUDE: 35.3403091°	LONGITUDE: 119.37672°	



PLANT COORDINATE AND DATUM NOTES

1. PLANT COORDINATES IN FEET EQUATE TO E. 61XXXXX AND N. 23YYYYY OF CALIFORNIA STATE PLANE COORDINATE SYSTEM (NAD 83 ZONE V.)
2. PLANT ELEVATION 100.00' EQUATE TO 288.50' ABOVE MSL (NAVD88.)
3. ACCURACY/TOLERANCE OF EMISSION POINT(S) COORDINATES ARE WITHIN A 50 FOOT RADIUS OF SOURCE POINT NOTED.
4. LOCATION OF EMISSION POINTS ARE SUBJECT TO COMPLETION OF DETAILED DESIGN BY LICENSORS AND EQUIPMENT SUPPLIERS.
5. SEE SHEETS 2 THROUGH 9 FOR INFORMATION ON COMPOSITION AND FLOW RATE FROM EACH SOURCE.
6. EMISSION POINT IS SHOWN FOR INFORMATION ONLY. ZERO EMISSIONS ARE EXPECTED DURING STEADY STATE OPERATION.

EMISSIONS SOURCES

ID	SOURCE	STATE PLANE COORD. (NAD83NSRS) EAST	NORTH	APPX. ELEVATIONS FROM GRADE (FT)
1	ASU COOLING TOWER	46053'-0"	9557'-8"	55'
2	POWER BLOCK COOLING TOWER	47732'-0"	8813'-0"	55'
3	PROCESS COOLING TOWER	48460'-0"	8813'-0"	55'
4	EMERGENCY ENGINES (GENERATORS)	47067'-5"	9864'-0"	20'
5	HRSG STACK	46924'-0"	10035'-0"	213'
6	EMERGENCY ENGINE (FIRE WATER PUMP)	46789'-0"	9348'-0"	20'
7	AUXILIARY BOILER (NOTE 6)	46924'-0"	9730'-0"	80'
8	TAIL GAS THERMAL OXIDIZER	47713'-7"	10681'-0"	165'
9	CO2 VENT (NOTE 6)	47501'-0"	10208'-0"	260'
10	SRU FLARE	47267'-0"	11147'-0"	250'
11	GASIFICATION FLARE	47267'-0"	11159'-0"	250'
12	RECTISOL FLARE	47610'-0"	11153'-0"	250'
13	FEEDSTOCK DRYER	47140'-3"	10013'-3"	305'
14	UREA PLANT HP ABSORBER	47850'-0"	9591'-0"	130'
15	UREA PLANT LP ABSORBER	47802'-0"	9575'-0"	50'
16	UREA PASTILLATION VENT	48075'-0"	9527'-0"	50'
17	FEEDSTOCK RAIL UNLOADING VENT	49035'-0"	9804'-0"	30'
18	FEEDSTOCK TRANSFER TOWER	49726'-0"	10805'-0"	100'
19	FEEDSTOCK CRUSHER VENT	47206'-0"	10805'-0"	100'
20	FEEDSTOCK TRUCK UNLOADING VENT	50631'-0"	9810'-0"	60'
22	FEEDSTOCK TRANSFER TOWER B	49533'-0"	9806'-0"	100'
23	UREA LOADING VENT 1	48902'-0"	9667'-0"	30'
24	UREA LOADING VENT 2	48942'-0"	9667'-0"	30'
25	GASIFICATION SOLIDS PAD	47323'-7"	9868'-7"	N/A
27	NITRIC ACID ABSORBER VENT	47797'-0"	9373'-0"	145'
27A	AMMONIUM NITRATE SCRUBBER VENT	47767'-0"	9392'-0"	40'
28	GASIFICATION SOLIDS TRANSFER TOWER	47322'-2"	9928'-4"	30'
29	GASIFICATION SOLIDS LOADING VENT	48932'-8"	9928'-6"	30'
30	UREA BUCKET ELEVATOR	48190'-0"	9485'-0"	50'
31	UREA TRANSFER TOWER 1	48570'-0"	9574'-0"	100'
32	UREA TRANSFER TOWER 2	48580'-0"	9574'-0"	100'
33	UREA TRANSFER TOWER 3	48570'-0"	9364'-0"	100'
34	UREA TRANSFER TOWER 4	48580'-0"	9364'-0"	100'
35	UREA TRANSFER TOWER 5	48575'-0"	9469'-0"	100'
36	AMMONIA UNIT STARTUP HEATER	47495'-0"	9500'-0"	80'

MAJOR STRUCTURES/ EQUIPMENT AND TANKS

ID	DESCRIPTION	APPX. ELEVATIONS FROM GRADE (FT)
A	ASU MAIN AIR COMPRESSOR ENCLOSURE	40
B	LIQUID OXYGEN STORAGE (LOX) TANK	90
C	AIR SEPARATION COLUMN CAN	200
F	FEEDSTOCK BARN	160
G	GASIFICATION STRUCTURE	305
O	COMBUSTION TURBINE GENERATOR STRUCTURE	50
P	HEAT RECOVERY STEAM GENERATOR STRUCTURE	90
Q	FLARE K.O. DRUMS (QTY 3)	35
R	POWER DISTRIBUTION CENTERS	25
S	AGR METHANOL WASH COLUMN	235
T	AGR REFRIGERATION COMPRESSOR STRUCTURE	40
W	RAW WATER TANK	100'DIA X 48'H
W2	TREATED WATER TANK	95'DIA X 40'H
W3	PURIFIED WATER TANK	75'DIA X 48'H
W4	BACKWASH TANK	65'DIA X 48'H
W5	UTILITY WATER TANK	50'DIA X 32'H
W6	DEMINERALIZED WATER STORAGE TANK	52'DIA X 40'H
X	FIREWATER STORAGE TANK	110'DIA X 48'H
Y	UREA STORAGE (4 DOMES)	162'DIA X 70'H
Z	METHANOL STORAGE TANK	40'DIA X 40'H
AA	AMMONIA STORAGE (2 TANKS)	90'DIA X 70'H
BB	UAN STORAGE (3 TANKS)	120'DIA X 48'H
CC	UREA RECLAIM LOADOUT BUILDING	70
DD	SULFUR STORAGE TANK	30'DIA X 24'H

(W, W2, W3, W4, W5, W6, X, Y, Z, AA, BB, DD: ABOVE GRADE TANKS)

0 100' 200' 400' 600' 800' 1000'

Source:
Fluor; HECA-SCS, 2012 AFC Update; Preliminary Emissions Sources Plot Plan;
Drawing No: A4UV-000-50-SK-0002, Rev. E (4/04/12)

HECA PLOT PLAN WITH EMISSION SOURCE LOCATIONS

May 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 1-2

5/29/12 rsa. T:\HECA-SCS 2012\GRAPHICS 2012\SJVAPCD Permit\Fig1-2_plotplan_emissions.ai

HECA LLC proposes to be the owner and operator of the IGCC facilities, and has the option to purchase the 453-acre Project Site, as defined below, from the site owner. HECA also holds an option to purchase the 653 acres that comprise the Controlled Area.

The transmission line ownership, up to the point of interconnect at the future Pacific Gas and Electric Company (PG&E) switching station, will be determined in the future based on input from PG&E and the California Independent System Operator (CAISO). The natural gas supply line will be owned by PG&E. The process water supply line and associated well field will be owned and operated by the Buena Vista Water Storage District (BVWSD). The potable water supply line will be owned by HECA LLC. The railroad spur will be owned by HECA LLC. OEHI will own and operate the CO_2 pipeline, as well as the EOR Processing Facility and associated infrastructure required for CO_2 EOR and sequestration.

1.2.2 Nature of Business

The proposed HECA facility is an IGCC polygeneration project that will produce low-carbon baseload electricity, low-carbon nitrogen–based products in an integrated Manufacturing Complex, and CO_2 for EOR.

1.2.3 Person to Contact Regarding Application

Julie Mitchell
Air Quality and Public Health Scientist
URS Corporation
4225 Executive Square, Suite 1600
La Jolla, CA 92037
Phone: (858) 812-9292
Fax: (858) 812-9293
julie.mitchell@urs.com

Marisa Mascaro
Executive Vice President, Legal and Regulatory Affairs
Hydrogen Energy California LLC
30 Monument Square, Suite 235
Concord, MA 01742
Phone: (978) 278-9529
MMascaro@scsenergyllc.com

1.2.4 Type of Entitlement

This document is an application for an Authority to Construct/Permit to Operate for the Project to be issued by the SJVAPCD. This application also contains supplemental information to the June 2009 PSD permit application to USEPA Region IX. The Project includes one Gasification Block, a single-train Gas Processing and Cleanup System, one Power Generation Block (one Mitsubishi Heavy Industries (MHI) 501 granular-activated carbon (GAC) combustion turbine, and one MHI steam turbine), one Manufacturing Complex, and other plant supporting process systems as described in Section 2.

1.2.5 Estimated Construction and Completion Dates

Construction of the new polygeneration facility is expected to occur over a 49-month overall construction period (42 months of site preparation and construction, and up to 18 months of commissioning and start-up, with overlap).

The Project milestones are anticipated to be as follows:

Commencement of pre-construction and construction activities	June 2013
Completion of construction	February 2017
Commencement of pre-commissioning and commissioning	March 2016
Commencement of commercial operation of the Project	September 2017

1.2.6 Application Status

This document is an original Authority to Construct/Permit to Operate application.

1.2.7 Compliance Certification

Hydrogen Energy California, LLC and SCS Energy California, LLC do not own or operate any facilities in the State of California; therefore, proof of compliance with applicable federal, state, and SJVAPCD emission limits, and applicable environmental standards, is not applicable.

This section provides a technical description of the proposed HECA facilities, including specific information on their equipment, processes, raw materials, and product. Data on the pollutant emissions resulting from the operation of the facilities are presented in Section 3. Figure 2-1, Overall Block Flow Diagram with Emission Sources, shows the interrelationships of the component processes within the HECA facility.

Section 2.1 describes the overall plot plan of the HECA Project, and identifies access points and tie-ins with off-site facilities. Detailed information on the equipment and processes of the major on-site Project components is provided in Section 2.2, resource inputs to the HECA facility are described in Section 2.3, and product outputs are discussed in Section 2.4.

2.1 SITE ACCESS AND LINEARS TIE-INS

Figure 1-2, HECA Plot Plan with Emission Source Locations, presents a scaled, overall plot plan for the Project. This figure identifies the primary site access, which will be from Dairy Road on the western side of the Project Site for personnel access, and Station Road on the eastern side of the Project Site for feedstock and other deliveries; there is also a railroad entrance, which is at the northwestern corner of the Project Site.

Table 2-1, Project Linear Tie-In Locations on Plot Plan, provides a list of the currently anticipated Project pipelines, communication, and electrical interfaces at the site boundaries.

Table 2-1
Project Linear Tie-in Locations on Plot Plan

Interface Description	Tie-In Location
Communications Conduit	Within other linear facility easements
Process Water Supply	Southwestern side of Plot
Potable Water Supply	Northeast side of Plot
Plant Wastewater Discharge	None (Zero Liquid Discharge)
Natural Gas Supply	Southwestern side of Plot
Carbon Dioxide Export	Southwestern side of Plot
Transmission Line	Northeastern side of Plot
Railroad Spur	Northwestern corner of Plot

Source: HECA, 2012.

2.2 HECA COMPONENT PROCESS DESCRIPTIONS

2.2.1 Solids Handling, Gasification, and Gas Treatment

2.2.1.1 Overview of Gasification Technology

Gasification is a chemical conversion process that can be used to convert solid feedstocks into syngas (see Table 2-2, Primary Gasification Reactions). The primary components of the syngas are CO and hydrogen (H_2), and the syngas is further processed in a gas treatment unit to produce hydrogen-rich fuel. See Table 2-3, Components of Syngas from Oxygen-Blown Gasification. This treatment of syngas is classified as a pre-combustion treatment process, and has advantages over a post-combustion treatment process that is used for pulverized-coal power plants. Specifically, the treatment and removal of CO_2 and sulfur in pre-combustion treatment occurs at higher pressures and lower volumetric flowrates, which increases the capture efficiency compared with post-combustion treatment of exhaust gas in a conventional power plant. The Project uses MHI oxygen-blown dry-feed gasification technology. The MHI gasifier incorporates a two-stage reaction that increases conversion of feedstocks to syngas and improves efficiency. MHI also uses a water wall to provide thermal protection for the vessel wall instead of a refractory lining. This increases the run length and availability of the equipment, and reduces the amount of time required to start up the unit.

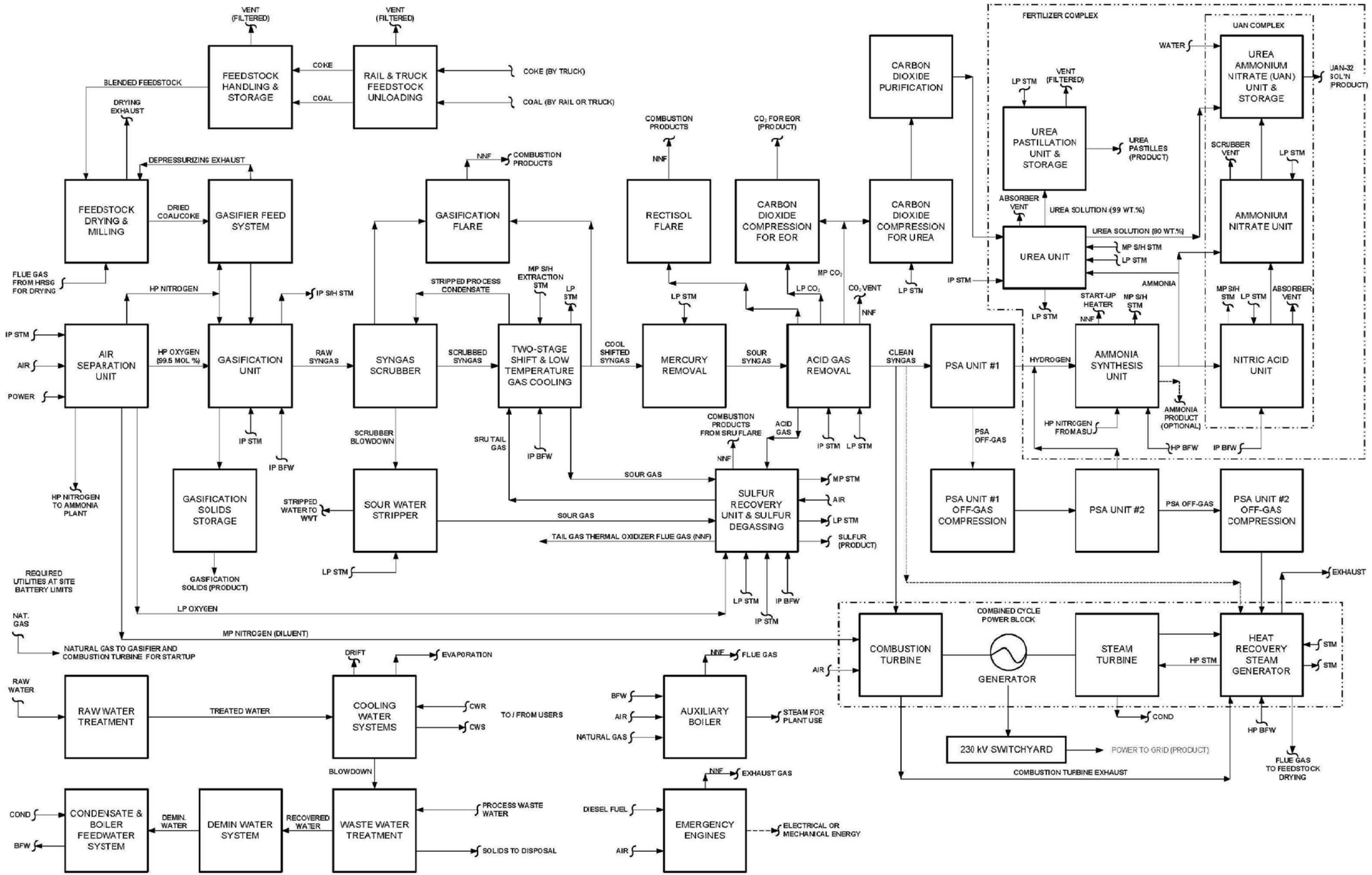
IGCC generally refers to the use of gasification technology to generate electricity in a Combined Cycle Power Block. However, products other than power may be co-produced in an IGCC plant. This Project will use a blend of 75 percent coal and 25 percent petcoke on a thermal input basis to produce electricity, low-carbon nitrogen-based products, and CO_2. The CO_2 will then be sold to OEHI, where it will be used for EOR, and be effectively sequestered in a closed-loop process.

Table 2-2
Primary Gasification Reactions

Devolatilization/= CH_4 + CO + Oils + Tars + C (char)	
$C + O_2 \rightarrow CO_2$	Oxidation – exothermic – rapid
$C + ½ O_2 \rightarrow CO$	Partial oxidation – exothermic – rapid
$C + H_2O \rightarrow CO + H_2$	Water/reaction – endothermic – slower than oxidation
$C + CO_2 \rightarrow 2CO$	Boudouard reaction – endothermic – slower than oxidation
$CO + H_2O \rightarrow CO_2 + H_2$	Water gas shift reaction – exothermic – rapid
$CO + H_2 \rightarrow CH_4 + H_2O$	Methanation – exothermic
$C + 2H_2 \rightarrow CH_4$	Direct methanation – exothermic

Source: Multiple publicly available sources.

Notes:
C = carbon
CH_4 = methane
CO = carbon monoxide
CO_2 = carbon dioxide
H_2 = hydrogen
H_2O = water
O_2 = oxygen



OVERALL BLOCK FLOW DIAGRAM WITH EMISSION SOURCES

May 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-1

Source:
Fluor; HECA-SCS, 2012 AFC Update; Overall Block Flow Diagram With Emission Sources;
Drawing No: A4UV-000-25-BFD-0002, Rev. 1 (3/29/12)

5/29/12 vsa. T:\HECA-SCS 2012\GRAPHICS 2012\SJV\APCD Permit\Fig2-1_overall_block_emission_sources.ai

Table 2-3
Components of Syngas from Oxygen-Blown Gasification

Constituent	Percent by Volume
Hydrogen	16–33
Carbon monoxide	33–55
Carbon dioxide	1–8
Water	0.1–9
Methane	0–1.5
Hydrogen sulfide	0.3–0.8
Carbonyl sulfide	0–0.1
Nitrogen + Argon	0.3–13
Ammonia + Hydrogen cyanide	0–0.3
Higher Heating Value	~200-300 Btu/scf

Source: HECA, 2012.
Notes:
Btu = British thermal unit
scf = standard cubic foot

The Project will achieve the strictest air emissions controls available for this type of equipment. In addition to providing a platform for efficient and cost-effective CO_2 removal, IGCC plants also minimize other air pollutants. Because the coal is not actually combusted, an IGCC plant can more effectively eliminate criteria air pollutants. In an IGCC plant, the air emissions controls remove pollutants from the syngas stream at a point in the process where the pollutants are concentrated and easily removed, instead of trying to eliminate them from the stack emissions, where treatment of a much greater stream of dilute flue gas would be required.

2.2.1.2 Feedstock Delivery, Handling, and Storage

2.2.1.2.1 Rail Unloading and Transfer Systems

HECA proposes to transfer all coal feedstock to the Project Site by rail. A new industrial railroad spur approximately 5 miles in length will connect the Project Site to the existing San Joaquin Valley Railroad (SJVRR) Buttonwillow railroad line, north of the Project Site. This railroad spur would also be used to transport some HECA products to customers. A rail unloading and transfer system would be constructed at the Project Site to unload coal from unit trains and convey it to the storage barn. This system accomplishes the following objectives.

- Unloads coal from unit trains; and
- Conveys the coal to storage in the coal barn.

The transfer conveyor is fully enclosed for weather protection and to control fugitive dust. The conveyor is provided with belt scales, magnetic separators, metal detectors, and safety switches, as required. All related coal feedstock buildings are fully enclosed. Dust suppression spray systems and multiple dust collection systems are used to control fugitive dust.

2.2.1.2.2 Truck Unloading and Transfer Systems

Petcoke will be delivered to the Project Site via over-the-road bottom-dump haul trucks. Truck transport would be via existing roads. In addition, a portion of the products of the HECA facility will be transported to markets by truck. At the Project Site, petcoke will be unloaded at the truck-dump unloading station. The truck dump has a single hopper below each unloading station. Petcoke from these hoppers is sent to the petcoke storage via belt feeders, unloading conveyor, and transfer conveyors. An as-received sample system is provided with the petcoke transfer conveyors. The concrete floor under the truck unloading system slopes to a sump. This sump is equipped with an installed sump pump to recycle water back to the wash-down system, or to forward it to the IGCC water reclaim system.

Once trucks have unloaded the petcoke, each vehicle exits and passes through a truck wash system, which sprays the entire truck with wash-down water (no soap added), and a specific spray system cleans the wheels. This is done to minimize or eliminate any dust and debris from being carried out and deposited on either the roads inside the Project Site or on public roads. The wastewater collected under the truck wash is routed to a sump that sends the wastewater back to the IGCC water reclaim system.

2.2.1.2.3 Feedstock Blending and Handling

Both coal and petcoke will be stored in a building with separate coal and petcoke storage piles. The coal and petcoke will be reclaimed at a set rate and blended as they are placed on conveyors for transfer from the storage building. The coal and petcoke blend will then flow to Gasification for further processing.

The transfer conveyor between the storage building and Gasification Block is fully enclosed for weather protection and to control fugitive dust. The conveyor is provided with belt scales, magnetic separators, metal detectors, and safety switches, as required.

2.2.1.3 Gasification

2.2.1.3.1 Feedstock Grinding and Drying

The MHI gasification system includes equipment to grind and dry the feedstock. The blended feedstock is stored in intermediate storage bins. The feedstock then flows to the grinding mills, where the particle size is reduced to that required for transport into the gasifier, and simultaneously dried. The heat source for feedstock drying is hot turbine exhaust gas from the heat recovery steam generator (HRSG). After drying the feedstock, the drying gases flow through a dust collection system before being vented through the coal-dryer stack.

2.2.1.3.2 Gasifier

The MHI oxygen-blown gasifier is a pressurized, upflow, entrained-flow slagging reactor with a two-stage operation. The MHI gasifier is a dry-feed system; and the reactor internals are protected by a membrane wall.

The reactor consists of two sections (or stages). The coal enters the gasifier at two separate points, with one portion being fed into the lower stage together with O_2, where it is gasified at

high temperature to produce CO and CO_2, in addition to water vapor. The temperature generated is sufficiently high to melt the coal ash. The molten coal ash flows down the membrane wall to the bottom of the gasifier, where it is quenched in a water bath and then removed using a lock hopper system.

The gas produced in the first stage rises to the second stage, where the remaining petcoke is added without any additional O_2. In this fuel-rich reducing environment, the key reactions that take place are the gasification of char to CO, and the shifting of CO and water to H_2 and CO_2. In the second stage, heat provided by the hot gas from the first stage is used to drive these endothermic gasification reactions. As a result, the second stage operates at a lower temperature than the first stage. Completing the gasification reactions at a lower temperature reduces the O_2 required and improves the efficiency of the gasifier. The produced syngas exits the second stage through a syngas cooler, generating steam in the process. This steam is used for power generation in the steam turbine of the Power Block. A cyclone and a filter are used downstream of the syngas cooler to collect the char and recycle it to the lower gasifier section to increase the overall carbon conversion efficiency. The raw syngas leaving the second stage of the gasifier is typically at a temperature of approximately 2,200 degrees Fahrenheit (°F), hot enough that negligible hydrocarbon gases and liquids are formed.

2.2.1.3.3 Gasification Solids and Water Handling

Gasification solids are comprised of vitrified (glass-like) material produced by melting the mineral matter in the coal and petcoke, and small amounts of unconverted carbon.

In the collection sump, the gasification solids are separated from the water and are accumulated for off-site transportation by rail or truck.

2.2.1.4 Syngas Scrubbing, Sour Shift, Low-Temperature Gas Cooling, and Sour Water Treatment

Hot, raw syngas from the gasifier is treated in the syngas Scrubber to remove chlorides. Removal of chlorides in the syngas Scrubber minimizes the potential to precipitate ammonium chloride in downstream equipment as the syngas is further cooled. The bottoms stream from the syngas Scrubber, along with sour water streams from the SRU, is sent to a sour water stripper. The sour gas from the stripper overhead is sent as a feed to the SRU. The stripper bottoms stream is sent to the Wastewater Treatment Unit for additional processing. Scrubbed syngas entering the Sour Shift Unit is rich in CO and water. The Sour Shift Unit employs the water-gas shift (WGS) reaction to convert CO and water to CO_2 and hydrogen. The WGS reaction proceeds as shown below:

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

The heat from the exothermic shift reaction is used to generate steam or to heat other process streams via cross-exchange, thereby improving overall plant efficiency. The WGS reaction is carried out in a two-stage process. Each of the reactors has a sulfur-tolerant catalyst bed composed of cobalt and molybdenum oxides. This catalyst also promotes the hydrolysis of carbonyl sulfide (COS) to hydrogen sulfide (H_2S).

Hydrogenated tail gas from the SRU is recycled to the Sour Shift Unit. This configuration eliminates a need to remove H_2S from the hydrogenated tail gas and also eliminates the need for atmospheric tail gas emissions.

Hot syngas from the sour shift reaction section is cooled and sent to the ammonia wash column, where it is washed with clean boiler feed water to remove any ammonia present in the syngas. Cooled, shifted, ammonia-free syngas exits the wash column and is sent to the Mercury Removal Unit. The bottoms stream from the ammonia wash column is sent to a separate sour water stripper. Most of the ammonia is concentrated in the stripper overhead stream, which is sent as a feed to the SRU. The stripper bottoms stream is recycled back to the syngas Scrubber.

2.2.1.5 Mercury Removal

In order to minimize potential mercury emissions, the Project has incorporated mercury capture technology. Tests of petcoke sources show occasional trace levels of mercury in the elemental analyses. Western sub-bituminous coals typically contain trace levels of mercury as well. Mercury is removed downstream of the Sour Shift and low-temperature gas cooling (LTGC) units, and at the coal dryer using activated carbon. After mercury removal, the product syngas is treated in the AGR Unit. These controls will reduce mercury emissions to a level that will comply with the new National Emission Standards for Hazardous Air Pollutants (NESHAP) for IGCC Electric Generating Units.

2.2.1.6 Acid Gas Removal

The term “acid gas” refers to vapor containing significant concentrations of acidic gases such as H_2S and CO_2. This section describes how acid gases are removed from the shifted syngas to produce a hydrogen-rich fuel that feeds the Combined Cycle Power Block. A portion of the hydrogen-rich fuel is also used to generate a high-purity hydrogen stream that serves as a feedstock to the Ammonia Synthesis Unit.

2.2.1.6.1 Rectisol® Process Description

In the Rectisol® unit, the shifted sour syngas feed is chilled prior to entering the pre-wash section, in which condensed or dissolved impurities are removed. The gas then flows to the absorber column, where it is contacted with methanol solvent for absorption of H_2S, other sulfur compounds, and CO_2.

Clean, hydrogen-rich fuel (very low in sulfur compounds and CO_2) exits the top of the absorber column. The clean, hydrogen-rich fuel is heated and sent to the Combined Cycle Power Block for use as fuel or to the PSA Unit for further purification.

The hydrogen-sulfide-laden solvent is withdrawn from the absorber column and flashed, with the flash gas recycled to the absorber column, and the separated liquid solvent sent to CO_2 separation columns. Carbon-dioxide–laden solvent from the absorber column is also sent to the CO_2 separation columns.

Separated CO_2 exits the top of the CO_2 separation columns and flows to CO_2 compression equipment. After compression, the CO_2 is transported to the OEHI CO_2 Processing Facility for CO_2 EOR.

CO_2-free solvent exiting the bottom of the CO_2 separation columns flows to the hot regenerator, where H_2S and other sulfur compounds are released from the solvent by increasing the temperature and stripping with methanol vapor generated in a reboiler. The separated acid gas exiting the top of the hot regenerator undergoes further processing in the SRU to recover liquid sulfur as a product.

The regenerated methanol solvent exiting the bottom of the hot regenerator, now CO_2- and H_2S-free, is cooled and returned to the absorber column for reuse.

A small portion of the regenerated solvent is sent to the methanol-water column for separation of water and impurities from the methanol by distillation. The methanol-rich overhead stream from the methanol-water column is returned to the hot regenerator. The separated column bottoms water is cooled and sent to the Wastewater Treatment Unit.

2.2.2 Power Generation

2.2.2.1 Summary

Combined-cycle power generation is one of the most efficient commercial electricity generation technologies available. The power-generation equipment used for the Project is similar to a conventional natural-gas combined-cycle plant, with the notable exception that substantial heat integration with the gasification process is included to maximize the recovery of useful energy both for internal and external process use and power generation. The Combined Cycle Power Block will include one single-shaft 405 MW MHI 501GAC® G-class, air-cooled advanced combustion turbine generator (CTG) and steam turbine generator (STG) configured to use hydrogen-rich fuel, one HRSG, and a water-cooled surface condenser. The CT, HRSG, and ST will convert chemical energy contained in the syngas fuel to electricity through the shaft power developed by the CT/ST generator, and through the thermal energy recovered from the CT exhaust. This exhaust gas is converted to high-energy steam in the HRSG and combined with the high-energy steam recovered in the gasification process to generate additional electricity in the ST. The G-class machine is arranged in a single-shaft configuration, where the CT and ST share a common shaft/generator.

Electrical power generation is distributed in the switchyard for transmission to the grid, and for satisfying the auxiliary loads within the facility.

2.2.2.2 Major Power Block Equipment Description

The major equipment of the Power Block is described in the following sections.

2.2.2.2.1 Combustion Turbine and Heat Recovery Steam Generator

The MHI 501 GAC® CT/ST generator will produce 405 MW of gross output. Exhaust gas from the turbine section is ducted through the HRSG to generate high-energy steam, which produces

additional electricity in the ST. Some of the exhaust gas is also ducted from the HRSG to Gasification to dry the feed, and will be discharged at the stack in that process block. Remaining exhaust gas at the HRSG is discharged through the HRSG stack. The combustion system is designed for operation on hydrogen-rich fuel. The combustion system is also equipped with separate fuel nozzles for natural-gas firing during start-up, shut-down, and equipment outages. The combustion system is designed to achieve low–nitrogen oxide (NO_X) emissions, while injecting nitrogen diluent and combusting hydrogen-rich fuels. When operating on natural gas, water is injected for NO_X control. Natural gas is used during start-up and shut-down of the CT and during periods of unplanned equipment outages (up to 2 weeks per year), but not during normal operations. Table 2-4, Combustion Turbine Generator, presents additional information.

The CT exhaust gas, supplemental hydrogen-rich fuel, and PSA off-gas for duct-firing are used as energy input into the HRSG.

Table 2-4
Combustion Turbine Generator

Model	MHI 501 GAC®
Fuels	H_2-rich fuel, natural gas (co-firing during transition between natural gas and H_2-rich fuel)
Inlet Air Cooling	Evaporative coolers, 85% effectiveness
Emissions Control Diluent	Nitrogen for H_2-rich fuel, water injection for natural gas
Ambient Temperature Range	20°F to 115°F, average 65°F
Ambient Pressure	14.54 psia/feet above msl
Exhaust Pressure Loss at 97ºF	18.0 inches H_2O
Air Extraction	Not included
H_2 and Diluent Temperature	302°F at the MHI interface
Base Load Generator Output	282 MW
Exhaust Flow and Temperature	5,315 kpph, 950°F at average ambient
Minimum Output in Emissions Compliance	60 percent of base load on syngas

Source: HECA, 2012.
Notes:
% = percent
°F = degrees Fahrenheit
H_2 = Hydrogen
H_2O = water
IGV = inlet guide vane
ISO = International Standards Organization standard conditions of 1 atmosphere 59 ºF, and 60 percent relative humidity
kpph = kilopounds per hour (thousands of pounds per hour)
MHI = Mitsubishi Heavy Industries
psia = pounds per square inch absolute
msl = mean sea level

2.2.2.2.2 Duct Firing

Additional steam generation will occur in the duct-firing system in the CT exhaust. The fuel to the duct burner will consist of a combination of hydrogen-rich fuel and off-gas from the PSA unit, both of which have relatively low heating values. The maximum expected firing rate for the duct burner is 360 million British thermal units per hour (MMBtu/hour). Backup natural-gas fuel will never be combusted in the duct burner.

2.2.2.2.3 Emission Control Systems

The Project is designed with state-of-the-art emission-control technology. HRSG emissions control systems are designed to meet BACT levels of NO_X, CO, sulfur dioxide (SO_2), and VOCs, based on the most current industry data and manufacturers' information. HRSG emission control systems are described in detail below.

A selective catalytic reduction (SCR) system is installed in the HRSG to reduce emissions of NO_X from the CT and duct burners to meet BACT requirements. An oxidation catalyst is also installed in the HRSG to reduce CO and VOC emissions in the same exhaust stream to achieve BACT levels**.** The HRSG stack is provided with a continuous emissions monitoring system (CEMS) to verify compliance with applicable air permit requirements.

The SCR system reduces NO_X emissions from the stack gases in the HRSG. Vaporized ammonia is mixed with dilution air and injected into the CT exhaust gas upstream of a catalytic system that converts NO_X and ammonia to nitrogen and water. This vaporized ammonia will come from the on-site ammonia plant storage tank.

The components in the SCR system are as follows:

- **Dilution air blower.** The blower delivers fresh air to be combined with the vaporized ammonia.

- **Ammonia injection grid**. The diluted ammonia is sent to an injection grid, where the ammonia stream is divided among various injection points upstream of a catalyst. The flow of ammonia to each injection point can be balanced to provide optimum NO_X reduction.

- **SCR catalyst**. The SCR catalyst provides the surface area and the catalyst material for ammonia and NO_X to react and form nitrogen and water. The SCR catalyst is installed in a reactor housing in the HRSG at the proper flue gas temperature-point for good NO_X conversion.

The oxidation catalyst is installed in the HRSG casing upstream of the SCR ammonia injection location to reduce CO emissions. The catalyst oxidizes the CO and VOCs produced from the CT and duct burners.

2.2.2.2.4 Continuous Emissions Monitoring System

The CEMS records the emissions out of the HRSG stack to comply with local, state, and federal emission requirements. The CEMS typically monitors the NO_X, O_2, and CO levels. The monitored emission parameters will be determined by the SJVAPCD. The CEMS uses control

system signals for CT power output and fuel gas to the CT to calculate the total mass rate of emissions released, and may also be used as part of the ammonia injection controls for the SCR system. The CEMS is designed, installed, and certified in accordance with the applicable SJVAPCD and USEPA standards for analyzer performance, data acquisition, and data reporting.

These systems sample, analyze, and record stack emission data for several specified pollutants. CEMS incorporates data handling and acquisition systems to automatically generate emissions data logs and compliance documentation. Alarms alert operators if stack emissions exceed specified limits. Each CEMS undergoes periodic calibration, audits, and testing to verify accuracy.

In addition to continuous monitoring, the Project will perform periodic stack emission tests to verify compliance with emission limits, as required.

2.2.2.2.5 Steam Turbine

The ST for the Project is an MHI reheat turbine. The ST is coupled to the generator through a clutch, along with the CT on a single shaft, and the ST exhaust steam is condensed in a water-cooled condenser.

2.2.2.2.6 Heat Rejection System

The excess thermal energy in the steam exhausted to the condenser is dissipated in the heat rejection system. This system is comprised of a condenser, a circulating water system, and a multi-cell cooling tower.

The condenser is a shell and tube heat exchanger with the steam condensing on the shell side under a vacuum, and the cooling water flowing through the tubes in a single- or double-pass design. The condensate collects in the condenser hotwell, where it supplies the condensate pumps that feed the HRSG.

The heat in the condenser is picked up by the circulating water system and transferred to the cooling tower. The cooling water system also transfers heat to the cooling tower from the hydrogen-cooled generator, and other power and gasification equipment.

During start-up, a separate set of auxiliary cooling pumps supply water from the cooling tower basin and pump it through plate-type closed cooling water (CCW) exchangers, and return the water to the cooling tower fill material. The CCW pumps circulate higher-purity water through the CCW exchangers that cool the water before it removes heat from the closed-circuit cooling water users. The use of a separate closed cooling water system also reduces the electric power load by enabling the shut-down of the large, main circulating pumps when the Power Block is in standby mode, ready to start, or following a ST shut-down.

2.2.3 Major Electrical Equipment and Systems

The Project will have a 230-kilovolt (kV) air-insulated switchyard for interconnection to a future PG&E switching station. The 230-kV transmission line is sized for the total plant output. Revenue metering is provided in the Project Switchyard on the transmission line to PG&E.

Start-up power for the Project is obtained by back-feeding from the 230 kV grid through the main transformer to the unit auxiliary transformers.

The Project's auxiliary loads are served by various Power Distribution Centers (PDCs). PDC-1 serves major 13.8 kV loads, including downstream 4160-V and 480-V PDCs, and large motor drivers. Each of the 4,160-volt (V) and 480 V PDCs has a double-ended substation configuration with two 100 percent sized transformers.

Dual 1.5 MW standby diesel generators provide emergency power to essential services in the event of a grid failure.

Medium-voltage (MV) and low-voltage (LV) switchgear, MV and LV motor control centers, 125 V direct-current batteries, chargers, uninterruptable power supply, and Distributed Control System In/Out racks are located indoors in pre-fabricated electrical PDCs with redundant heating, ventilation, air conditioning units. The Major Electrical Equipment will be in accordance with American National Standards Institute/Institute of Electrical and Electronic Engineers/National Electrical Manufacturers Association/American Society for Testing and Materials standards. The electrical system design and installation are in accordance with the National Electrical Code.

2.2.4 Manufacturing Complex

2.2.4.1 Pressure Swing Adsorption Unit

A portion of clean hydrogen-rich fuel from the AGR Unit is sent to the PSA Unit to generate a high-purity hydrogen gas stream for use as a feedstock to the Ammonia Synthesis Unit. The off-gas from the PSA unit is compressed and sent to the HRSG for use as duct-burner fuel. Two PSA Units in series are used to maximize hydrogen recovery.

2.2.4.2 Ammonia Synthesis Unit

The high-purity hydrogen stream from the PSA Unit and a nitrogen stream from the Air Separation Unit are the two primary feedstocks for the Ammonia Synthesis Unit. The major steps in the process are described below.

The hydrogen and nitrogen feed streams are first compressed to a high pressure and then mixed with recycled gas in the syngas compressor (electric powered). The combined mixture is then further compressed, heated, and fed to the ammonia (NH_3) synthesis converter, where the exothermic conversion to ammonia takes place over an iron-based catalyst as follows:

$$3\ H_2 + N_2 \leftrightarrow 2\ NH_3$$

The hot ammonia synthesis converter effluent is first cooled by generating steam in the waste heat boiler. The converter effluent is then further cooled in a series of exchangers to condense the ammonia product and separate it from the vapor stream in the primary separator. The vapor stream from the primary separator is recycled to the syngas compressor while the liquid ammonia product is first processed for the removal of inert substances, and then it is routed to storage.

The cold liquid ammonia storage system uses two vertical, cylindrical steel tanks, each housed in its own unique second vessel with double integrity, elevated above ground on a concrete pedestal, surrounded by a concrete barrier. A vapor recovery system is included to prevent any product losses. The tanks have sufficient storage capacity to support a cold start-up of the Ammonia Synthesis Unit. Additionally, the capacity of the tanks enables the production rate of urea pastilles and UAN solution to remain relatively constant as the IGCC plant undergoes on-peak and off-peak operations. The liquid ammonia is pumped from the tanks to the various users within the facility.

Ammonia is intended to be used on site to produce urea pastilles and UAN solution, and as the reagent for the SCR NO_X emission control system. However, the plant has also been designed with facilities to load liquid ammonia for sale onto railcars or into trucks for off-site shipment to allow for future operational flexibility.

A natural-gas–fired start-up heater is provided in the Ammonia Synthesis Unit to raise the catalyst bed temperatures during initial plant commissioning, or during start-up after a plant maintenance outage.

The Ammonia Synthesis Unit also contains an ammonia refrigeration system to provide the chilling required for cooling the converter effluent stream and the ammonia product stream, and to recover and condense ammonia vapor from the ammonia storage tanks.

2.2.4.3 Urea Unit

CO_2 recovered in the AGR Unit is compressed and treated in the CO_2 Purification Unit to remove any trace sulfur compounds and produce very high-purity CO_2 for urea synthesis. Liquid ammonia from the upstream Ammonia Synthesis Unit is pumped and combined with this CO_2 stream in the Urea Reactor. The following exothermic reaction proceeds quickly:

$$2\ NH_3 + CO_2 \leftrightarrow NH_2\text{-}CO\text{-}ONH_4 \text{ (ammonium carbamate)}$$

Ammonium carbamate is then dissociated to urea and water through the application of heat. The reaction kinetics for urea production are slower than those for the ammonium carbamate reaction.

$$NH_2\text{-}CO\text{-}ONH_4 \leftrightarrow NH_2\text{-}CO\text{-}NH_2 \text{ (urea)} + H_2O$$

Because the above reaction does not proceed to completion, additional steps are necessary to produce the desired urea product. Various combinations of dissociation, condensation, recycle of unconverted reactants, and stripping are used to complete the conversion to urea.

Finally, the intermediate urea solution is concentrated to provide the required feeds to the UAN Complex and to the Urea Pastillation Unit. Vacuum evaporator/separator systems are used to produce the required urea solutions. A single stage unit can provide approximately 80 weight percent urea feed to the UAN complex, and a multistage system is required to provide the approximately 99 weight percent urea melt for the pastillation unit. These solutions are then pumped to the final stage in their respective production processes. Vapors from the vacuum

system are scrubbed in an absorber using process condensates. The treated vapors (inert substances) are vented. The process condensates are recycled within the Urea Unit.

The capacity of the Urea Unit is sufficient to provide the combined urea product for both downstream UAN and pastillation production requirements. An intermediate urea solution surge tank is provided to enable continuous production, should operations of either the upstream or downstream systems be briefly interrupted.

2.2.4.4 Urea Pastillation Unit and Pastille Handling

Pastillation technology converts the urea melt into high-quality pastilles. Pastillation is selected due to its ability to minimize emissions of particulate matter and ammonia. A drop-former deposits uniform droplets onto a moving belt. These droplets solidify on the belt to produce a uniform pastille product. The heat of crystallization is removed by spraying the underside of the belt with cooling water. At no point in the process does the cooling water contact the urea product. After they have cooled and solidified, the urea pastilles are removed from the belt by an oscillating scraper. The section above the moving steel belt is enclosed with a hood and vented.

The urea pastille handling system collects urea pastilles from the Urea Pastillation Unit and conveys them to the bulk storage/rail and truck loadout facility.

The system accomplishes the following objectives:

- Receives urea pastilles from the Urea Pastillation Unit;
- Conveys the urea pastilles to the urea storage domes;
- Maintains a low-humidity atmosphere inside the storage domes to prevent the urea pastille, which is hygroscopic, from absorbing moisture;
- Reclaims the urea pastilles; and
- Conveys the urea pastilles to the urea loadout system.

All conveyors are fully enclosed in tubular galleries for weather protection and for control of fugitive dust. All urea-handling buildings are fully enclosed with roofing and siding. Dust collection systems are used to control dusting and fugitive dust emissions.

2.2.4.5 Urea Ammonium Nitrate Complex

In order to produce UAN solution, it is necessary to produce several intermediate products. These include nitric acid (HNO_3), ammonium nitrate (NH_4NO_3), and urea (NH_2-CO-NH_2). The following sections provide a brief overview of each of these processes.

2.2.4.5.1 Nitric Acid Unit

Nitric acid production is a three-step process consisting of NH_3 oxidation, nitric oxide (NO) oxidation, and absorption. In the ammonia oxidation step, ammonia from the Ammonia Synthesis Unit is oxidized by air at high temperatures as it passes over a platinum-based catalyst. The exothermic oxidation reaction proceeds as shown below:

$$4\ NH_3 + 5\ O_2 \rightarrow 4\ NO + 6\ H_2O$$

The hot effluent from the reactor is cooled via steam generation or cross-exchange with another process stream. Nitric oxide formed during the ammonia oxidation step must also be oxidized. In order to accomplish this, the process stream is cooled. Nitric oxide reacts non-catalytically with O_2 to form nitrogen dioxide (NO_2):

$$2\ NO + O_2 \rightarrow 2\ NO_2$$

Next, the nitrogen dioxide is further cooled and introduced into an absorption tower along with water. Nitric acid is formed via the following reaction:

$$3\ NO_2 + H_2O \rightarrow 2\ HNO_3 + NO$$

An additional air stream is introduced to re-oxidize the nitric oxide formed in the above reaction. This air stream also helps to remove any dissolved nitrous oxide present from the acid product.

Tail gas from the absorber column is cleaned before being vented. Catalytic decomposition and reduction of both nitrous oxide (N_2O) and NO_X are used to control emissions. The tail gas abatement unit complies with BACT requirements.

2.2.4.5.2 Ammonium Nitrate Unit

Ammonium nitrate (NH_4NO_3) solution is produced via a neutralization reaction between gaseous NH_3 and aqueous HNO_3. The exothermic reaction proceeds as follows:

$$NH_3 + HNO_3 \rightarrow NH_4NO_3$$

The water produced in the aqueous phase neutralization reaction is reused in the process.

Ammonium nitrate is produced and stored as a water solution (rather than in the solid form) to enhance process safety.

2.2.4.5.3 Urea Ammonium Nitrate Unit

The ammonium nitrate solution and the urea solution are metered, mixed, and cooled. Depending upon the concentration of the feedstock solutions and the desired product specifications, water may be added in as well. The final product is UAN, an aqueous UAN solution.

2.2.4.6 UAN Solution Storage and Handling

The UAN solution is stored in tanks, and then loaded into railcars or tank trucks for shipment.

2.2.5 Supporting Process Systems

2.2.5.1 Natural Gas Fuel System

2.2.5.1.1 Natural Gas Metering Station

The natural gas fuel system provides natural gas to all Project components at the required pressure, temperature, and flow rates. The natural gas underground pipeline enters the Project

Site at the Natural Gas Metering Station. The metering station is provided by the gas supplier and contains the gas revenue meters and gas analyzers. The gas metering station also contains a knock out (KO) drum and filter. The Project takes custody of the natural gas at the outlet of the metering station.

2.2.5.1.2 High-Pressure Natural Gas

High-pressure natural gas is provided to the gasifier for start-up and to the CT during plant start-ups and shut-downs and as a backup fuel when the hydrogen-rich fuel is unavailable. If the natural gas pressure is below the minimum required then the natural gas compressor is placed in operation. This compressor is electric driven. The natural gas to the CT passes through a KO drum, is heated with an electrical heater, and is filtered before entering the CT fuel control skid.

2.2.5.1.3 Low-Pressure Natural Gas

Low-pressure reduction stations and a KO drum are provided to supply the Project's other low-pressure natural gas users (i.e., flares, Auxiliary Boiler, Tail Gas Thermal Oxidizer, and the Ammonia Plant Start-Up Heater).

2.2.5.2 Air Separation Unit

The ASU will be designed, built and permitted by HECA, then owned and operated by a third-party Industrial Gas Company (IGC), although will be permitted by HECA and is included in this permit application. It produces a high-pressure, high-purity O_2 stream for use in the gasifier, as well as a low-pressure, high-purity O_2 stream for use in the SRU. In addition to O_2, the ASU provides high-purity nitrogen for use in the ASU, the CT (diluent), and various users within the Gasification Block.

The ambient air is filtered, compressed, dried, and cooled to cryogenic temperatures. The O_2 and nitrogen are then separated by cryogenic distillation within a heavily insulated cold box. Because operating temperatures for air separation are at cryogenic levels, distillation equipment is enclosed within cold boxes and insulated from heat leakage.

2.2.5.3 Sulfur Recovery and Tail Gas Compression Unit

Acid gas from the AGR unit, sour gas streams from the two sour water strippers, and various plant vents are fed to a SRU. A portion of the H_2S in the feed is oxidized to SO_2 in a reaction furnace. The resulting SO_2 reacts with the remaining H_2S in the correct ratio to form elemental sulfur. These reactions proceed as shown below:

$$H_2S + 3\ O_2 \rightarrow SO_2 + H_2O$$
$$2\ H_2S + SO_2 \leftrightarrow 3\ S + 2\ H_2O$$

Hot effluent gases from the reaction furnace are cooled in the waste heat boiler by generation of 600 pounds per square inch gauge (psig) steam. The tempered effluent gas is sent to the first condenser, where the temperature is decreased further to condense and recover elemental sulfur. Low-pressure steam is generated in the first condenser. Gas leaving the first condenser is then reheated before entering a catalytic reactor to further promote the H_2S and SO_2 reaction to

elemental sulfur, followed by a condenser to recover additional sulfur. One additional reheater, reactor and condenser follow.

Sulfur recovered in the three condenser stages is sent to a Sulfur Degassing Unit to reduce the concentration of H_2S dissolved in the sulfur product. After degassing, the liquid sulfur product is sent to a storage tank and ultimately shipped from the facility via rail or truck.

SRU effluent gases exiting the final condenser are directed to the Tail Gas Treating Unit (TGTU) hydrogenation equipment, which converts the various sulfur compounds remaining in the gas, back to H_2S. Water is condensed out of the hydrogenated tail gas in a quench tower, after which it is compressed and recycled to the Sour Shift Unit. This configuration minimizes sulfur emissions from the facility and eliminates the need for a TGTU amine section. This configuration also recovers the CO_2 that would be emitted by a conventional TGTU.

The SRU will include both ammonia-destruction and O_2-enrichment technology in the reaction furnace, in addition to the degassing technology used in treatment of the product sulfur. Oxygen enrichment technology uses high-purity O_2 rather than air in the combustion section of the SRU, thereby decreasing the volumetric flow of gas through the entire unit. The use of O_2 increases the temperature in the reaction furnace to a level that destroys the ammonia present in the feed gases. Ammonia destruction technology is a critical part of the SRU design. Complete destruction of ammonia in the reaction furnace helps to prevent the potential for ammonia salts to foul downstream equipment.

2.2.5.3.1 Sulfur Storage and Handling

As stated above, the degassed liquid sulfur product is stored in a tank for shipment via railcars or tank trucks.

2.2.5.4 Carbon Dioxide Compression and Pipeline

More than 90 percent of the carbon in the raw syngas is captured in the form of a highly concentrated CO_2 stream.

2.2.5.4.1 Compression and Pipeline

CO_2 is transported by pipeline to EHOF for CO_2 EOR and resulting sequestration. In order for the CO_2 to be transported, it must first be compressed. The CO_2 compressor is electric driven. The CO_2 that will be compressed comes from the AGR Unit. After processing by the AGR unit, the CO_2 is very dry, which avoids pipeline and equipment corrosion.

The minimum pressure requirement for the CO_2 pipeline is 2,500 psig. Once the CO_2 pressure reaches approximately 1,200 psig it becomes super-critical. Super-critical refers to a material at a temperature and pressure above its critical point, where there is no defined phase difference between liquid and vapor. Under these conditions, heating or cooling the fluid changes its density, but it does not develop into a separate liquid phase. High-pressure compression is needed for CO_2 injection operations and to keep the CO_2 in a super-critical phase throughout the CO_2 pipeline. The stream of CO_2 in the pipeline is at least 97 percent pure CO_2.

The pipeline facilities consist of the pipeline, metering, one pig launcher, one pig receiver, cathodic protection system, two main block valves and two additional emergency shut-down valves, as specified by the California State Fire Marshal.

The CO_2 is delivered to the OEHI CO_2 Processing Facility for injection into deep underground hydrocarbon reservoirs for CO_2 EOR and resulting sequestration.

2.2.5.4.2 Carbon Dioxide Compression and Purification

A portion of the low-pressure CO_2 gas from the AGR Unit is compressed and purified to remove sulfur-bearing compounds. The purified CO_2 gas is sent to the Urea Unit for use as a feedstock.

2.2.5.5 Heat Rejection Systems

Mechanical draft cooling towers are used for indirect heat rejection where low process outlet temperatures are critical to overall plant efficiency. Mechanical draft cooling towers serve multiple heat loads in more than one process unit.

The Project has three mechanical draft cooling towers (one for the Combined Cycle Power Block, the second for the Gasification Block/Process Units and the third dedicated for the ASU) that are described below. The configuration of this cooling water system also is similar to that employed for the ASU and Process Cooling Water Systems. The cooling towers use treated water from the water treatment plant as makeup. Cooling-tower blowdown from the cooling towers is directed to the water treatment plant.

The air coolers are dedicated to specific services, primarily in the Sour Shift, LTGC, SRU/ TGTU, and Sour Water Stripper (SWS) units for heat rejection.

2.2.5.5.1 Power Block Cooling Tower

The largest heat rejection load in the Project is the ST surface condenser in the Combined Cycle Power Block. The main cooling water pumps supply water from the cooling tower basin and pump it through the surface condenser tubes and back to the top of the cooling tower cells. The return water flows into distribution piping below high-efficiency drift eliminators and above the cooling tower fill material. Electric motor driven–induced draft fans move air up through the tower fill material, contacting the cooling water with air and promoting evaporative cooling. A chemical feed system will supply water conditioning chemicals to the circulating water to minimize corrosion and control the formation of mineral scale and biofouling. Sulfuric acid will be fed into the circulating water system for alkalinity reduction to control the tendency for scaling. The acid feed system will consist of storage and two full-capacity metering pumps. A polyacrylate solution is also fed into the circulating water system to inhibit scale formation. This system also requires storage, and two full-capacity metering pumps. Sodium hypochlorite is added to prevent biofouling in the circulating water system. The system requires storage, and two full-capacity metering pumps.

The cooling tower is provided with high-efficiency drift eliminators designed to reduce drift to less than 0.0005 percent of the circulating water flow rate.

2.2.5.5.2 Process Cooling Tower

The design of the Process Cooling Water System is similar to that of the Power Block Cooling Water System described above. The major heat rejection duties are from the CO_2 compressor and the AGR refrigeration unit. This compressor is electricity driven. Cooling water is also supplied to the Gasification, Shift, LTGC, SRU/TGTU, SWS, Manufacturing Complex, and other miscellaneous users. The process cooling tower has a cooling water basin, pumps, and piping system. The tower is supplied with high-efficiency drift eliminators designed to reduce drift to less than 0.0005 percent of circulation.

2.2.5.5.3 Air Separation Unit Cooling Tower

The ASU cooling tower will be owned and operated by a third party IGC, although will be permitted by HECA and is included in this permit application. The Project will supply the IGC with treated makeup water, and will also treat the ASU cooling tower blowdown in the Project's water treatment plant. The following description reflects the IGC's cooling water system design.

The ASU Cooling Water System design is also similar to that of the Power Block Cooling Water System. The major heat rejection duties are from the main air compressor intercooler and aftercooler, the booster air compressor intercooler, and the nitrogen compressor intercooler. These compressors are electricity driven. The ASU cooling tower is located in the ASU near the cooling loads. The ASU cooling tower has separate pumps and piping systems and is operated independently of the other cooling water systems. The ASU cooling tower is supplied with high-efficiency drift eliminators designed to reduce drift to less than 0.0005 percent of circulation.

2.2.5.6 Auxiliary Boiler

The auxiliary boiler is a pre-engineered shop-fabricated package boiler that will provide steam for pre-start-up equipment warm-up and for other miscellaneous purposes when steam from the Gasification Block or HRSG is not available. During typical operation, the auxiliary boiler may be kept in warm standby (steam sparged, no firing) or cold standby (no sparging), and will not have emissions. When operating, the boiler will produce a maximum of about 150,000 pounds per hour of steam and will be fueled by natural gas. The boiler will be equipped with low-NO_X burners and SCR to minimize emissions.

2.2.5.7 Flares

Flaring will occur only during start-up of the plant, from outages, or during emergencies. The previous design necessitated regular rotation of three gasifiers into and out of service to facilitate periodic maintenance of the gasifier refractory and other critical gasifier system components. The rotation of each gasifier into service after maintenance required flaring of syngas from the time of light-off until the syngas was up to pressure and within specification. The new design uses a single, 100-percent-capacity MHI gasifier with an internal membrane wall that requires significantly less maintenance, eliminates rotations, and requires less syngas flaring events than a refractory-lined gasifier.

Although the plant is designed to avoid flaring during steady-state operations, flares are needed to protect the plant operators and equipment. The plant employs three pressure-relief systems

and their corresponding flares (Gasification, Rectisol®, and SRU) for this purpose. All three flares are conventional elevated flares, and will be provided with natural gas assist as required. Vessels, towers, heat exchangers, and other equipment are connected to piping systems that will discharge gases and vapors to a relief system in order to prevent excessive pressure from building up in the equipment during upsets and emergencies. The flares also allow safe venting of equipment during routine start-up and shut-down operations.

During non–start-up plant operation, the three flares will be operated in a standby mode with only minimal emissions from the natural-gas pilot flames. As explained below, the Gasifier and SRU flares will be also be used to occasionally flare excess start-up gases in a safe manner.

2.2.5.7.1 Gasification Flare

The Gasification Unit is provided with an elevated flare to safely flare excess gas during gasifier start-up operations or during upset conditions. Syngas sent to the flare during planned flaring events is filtered, water-scrubbed, and sulfur-free. Flaring of untreated syngas or other streams within the plant will only occur as an emergency safety measure during unplanned plant upsets or equipment failures.

2.2.5.7.2 Sulfur Recovery Unit Flare

An SRU Flare will be used to safely flare gas streams containing sulfur during start-up and shut-down (as described further in this section), and gas streams containing sulfur during unplanned upsets or emergency events. Acid gas derived from the AGR, and SWS overhead is routed to the SRU for recovery as elemental sulfur. During cold plant start-up of the Gasification, AGR, and Shift Units, these acid gas streams will be diverted to the SRU Flare header for a short time. To reduce the emissions of sulfur compounds during SRU or TGTU shut-down, the acid gas is routed to the emergency caustic scrubber, where the sulfur compounds are absorbed with caustic solution. After scrubbing, the gas is then routed to the elevated SRU Flare stack via the SRU Flare KO drum. Fresh and spent caustic tanks and pumps are provided to allow delivery of fresh caustic and disposal of spent caustic.

2.2.5.7.3 Rectisol® Flare

Cold reliefs and vents from the AGR Unit and its associated Refrigeration Unit, and the Ammonia Synthesis Unit are collected in the Rectisol® Flare header. The Rectisol® Flare header is used only in start-up, shut-down, emergencies, or plant upsets, and contains gases that can be below the freezing point of water. For this reason, the Rectisol® Flare header gases are segregated from the wet gases in the Gasification Flare header.

2.2.5.7.4 Carbon Dioxide Vent

The CO_2 Venting System consists of a CO_2 vent header, vent KO drum, and a CO_2 vent stack. The system is used to vent incombustible, high-purity CO_2. The vent gas is generated from reliefs, start-up/shut-down vents, and venting when the CO_2 compression, transportation, or injection system is unavailable.

2.2.5.8 Emergency Engines

The following is a description of the emergency engines required for the Project. These engines are fueled using ultra-low-sulfur diesel fuel.

2.2.5.8.1 Emergency Diesel Generator

Two 2,000 kilowatt (kW) standby diesel generators in an outdoor enclosure will be connected via stepdown transformers to supply emergency essential service power to critical lube oil and cooling pumps, gasification and auxiliary steam systems, station battery chargers, uninterruptible power supply, heat tracing, control room, emergency exit lighting, and other critical plant loads.

A Local Control Panel will be situated on the diesel generator with standard microprocessor-based engine and generator controls, interlocks, metering, alarms, and synchronizing system. Remote control of the diesel generator shall be from Distributed Control System operators via a fiber optic cable to the control system.

2.2.5.8.2 Diesel Firewater Pump

One approximately 600-horsepower standby diesel-driven firewater pump will be adjacent to the firewater tank.

2.2.5.9 Plant and Instrument Air

Utility and instrument air for the entire plant is supplied by the ASU. Backup air is provided by an air compressor/dryer skid.

Primary plant service and instrument air is extracted from the ASU air-compression equipment and cooled. This air is clean and dry, and is fed directly to the plant and instrument air distribution system without further conditioning.

Secondary backup plant and instrument air is supplied from a stand-alone package air compressor/dryer/accumulator skid. The quality and quantity of air provided from this source is similar to that of the primary air system.

Both primary and secondary air sources are integrated and piped to the plant-wide distribution systems. The instrument air piping distribution system is sized to ensure that adequate quantities are supplied to the various instrument and control air consumers. Accumulators/volume bottles are installed near large intermittent air consumers (i.e., fast-acting control valves) to make certain that the required response times are attained.

Project service air system utility stations are positioned throughout the facility to provide plant air for maintenance activities. The source of the air to these utility air users is automatically shut off on low instrument air pressure. This feature ensures that priority is given to the instrument air system to make certain that adequate volumes are available to safely operate and control the facility.

2.3 RESOURCE INPUT

The feedstocks for the Project include the following, and their sources, characteristics, and usage within the HECA processes are discussed below:

- California petcoke and western sub-bituminous coal;
- Natural gas;
- Water;
- Oxygen; and
- Nitrogen.

2.3.1 Petcoke and Western Sub-Bituminous Coal

Coal is an abundant, domestic feedstock exhibiting stable supply compared to oil and natural gas resources. Securing a domestically available, long-term, stable feedstock will enable the Project to provide dependable low-carbon hydrogen-generated electricity, and to assist in meeting future electrical power needs and supporting a reliable power grid.

The Project expects to obtain its western sub-bituminous coal from New Mexico. Based on the design plant production rate, the Project will consume 4,580 short tons per day (stpd) of coal (nominally 1.6 million short tons per year [stpy]). Several western sub-bituminous coal mines that can supply coal meeting Project technology requirements in terms of ash composition and other characteristics have been identified. The Project is in the process of discussing contractual terms with relevant entities. The coal will be transported to Kern County by rail. For the purpose of compliance with the California Environmental Quality Act (CEQA) and the National Environmental Policy Act (NEPA), HECA evaluated two alternatives for the transportation of the coal within Kern County to the Project Site. These alternatives were described in detail in the AFC Amendment that was filed in May 2012. The alternatives consisted of the transfer of the coal onto trucks at the existing coal transloading facility in Wasco, and transportation by a new railroad spur to the Project Site. This application describes only the railroad spur transportation alternative.

The petcoke that will be used as a feedstock for the Project is a byproduct from the oil-refining process, and supplies are expected to be readily available to meet Project requirements. Petcoke most likely will be supplied from refineries in the Los Angeles or Santa Maria areas. In all, approximately 16,000 stpd (6.0 million stpy) of fuel-grade petcoke are produced by major California refineries. Five of these refineries are in the Los Angeles area, and one is in central California. At steady-state operation feeding 25 percent petcoke, the Project would consume about 7 percent of this total in-state production (around 1,140 stpd, or 400,000 stpy). Currently, petcoke is trucked from California refineries to ports for export to other nations, where it is burned in conventional furnaces and boilers that release CO_2 and other air pollutants directly into the air. In contrast, HECA will capture more than 90 percent of the CO_2 and sell this commodity to OEHI, where it will be used for EOR and effectively sequestered in a closed-loop process.

Transportation of coal to the Project Site will occur by train using a new railroad spur that will deliver the coal to the Project Site. Hauling distances for petcoke are short enough to favor truck movements. Accordingly, all petcoke transportation to the Project Site will occur via truck.

Coal and petcoke deliveries to the Project Site will be unloaded and stored at the Project Site in the coal barn, which will be designed to contain feedstock sufficient for 30 days of operation (approximately 172,000 tons of coal and petcoke). The rail and truck unloading systems, feedstock reclaiming and blending system, and pre-crushing system will be equipped with dust collection systems to minimize particulate emissions. The grinding mill feed bins will be totally enclosed and will include baghouses to remove airborne dust. Petcoke and coal will be transported from the unloading systems to the enclosed barn, the pre-crushing system, and the grinding mill feed bins in enclosed conveyors with dust collection systems.

2.3.2 Feedstock Quality and Plant Operations

Feedstock Flexibility

The ability of the Project to accept a variety of petcoke and coal feedstocks will enable it to increase the number of potential fuel suppliers, and to minimize fuel costs.

Sulfur Content

Potential sources of coal investigated for the Project have an average sulfur content of approximately 1 percent. Petcoke sulfur levels may be variable over time as heavier crudes are processed at a number of California refineries. However, the Project's sulfur recovery system is able to handle feedstock blends with variable sulfur levels, and therefore will accommodate both current and expected future sulfur levels in California petcokes. Higher-sulfur petcoke generally costs less than lower-sulfur petcoke in the marketplace, and the ability to process higher-sulfur feedstocks will help minimize fuel costs.

2.3.3 Transportation and Logistics

Trucking

A number of trucking firms with petcoke-handling experience have been identified and engaged in preliminary discussions. All have expressed interest in serving the Project. The use of Los Angeles and central California–area petcoke would minimize truck shipments, thus minimizing emissions and transportation costs.

Rail Shipments

Because of the distances involved and desire to minimize truck traffic, western sub-bituminous coal procured for the Project will be transported by railroad to Kern County and delivered directly to the Project Site via a new railroad spur. The railroad spur will also be used to transport products from the Project Site during operations.

Storage

The Project will provide 30 days of feedstock storage (based on anticipated usage rates) on site, in an enclosed barn.

Feedstock Characteristics

A representative feedstock analysis is provided below for each feedstock. The representative feedstock analysis for petcoke is provided in Table 2-5, Typical Analysis for Petcoke. The representative feedstock analysis for western sub-bituminous coal is provided in Table 2-6, Typical Analysis of Sub-Bituminous Coal.

Table 2-5
Typical Analysis for Petcoke

Ultimate Analysis, wt% (dry)	
Carbon	84.4
Hydrogen	4.0
Nitrogen	4.0
Sulfur	6.0
Oxygen	0.6
Ash	1.0
Moisture, wt% (AR)	15.0
Chloride Content, ppmw (dry)	250
Gross Heating Value, Btu (dry)	14,579
Bulk Density, lb/ft^3 (AR)	50
Ash Analysis, ppmw (dry)	
Vanadium	1,200
Nickel	1,200
Iron	1,000
Chromium	10
Sodium	400
Calcium	400

Source: HECA, 2012.

Notes:
% = percent
< = less than
> = greater than
AR = as received
Btu/lb = British thermal units per pound
lb/ft^3 = pounds per cubic feet
ppmw = parts per million by weight
wt% = weight percent

Table 2-6
Typical Analysis of Sub-Bituminous Coal

Ultimate Analysis, wt% (dry)	
Carbon	60.4
Hydrogen	4.5
Nitrogen	1.0
Sulfur	1.09
Oxygen	11.7
Ash	21.3
Moisture, wt% (AR)	14.8
Gross Heating Value, Btu/lb (dry)	10,860
Mercury Content, ppmw (dry whole coal basis)	0.09
Ash Mineral Analysis, wt% (ignited basis)	
Silicon Oxide	59.3
Aluminum Oxide	22.9
Titanium Dioxide	1.0
Sulfur Trioxide	3.4
Calcium Oxide	4.8
Potassium Oxide	1.1
Magnesium Oxide	1.0
Sodium Oxide	0.4
Iron Oxide	5.7
Phosphorous Oxide	0.1
Strontium Oxide	0.1
Barium Oxide	0.2
Manganese Dioxide	< 0.1

Source: HECA, 2012.

Notes:
< = less than
AR = as received (with delivered free moisture)
Btu/lb = British thermal units per pound
ppmw = parts per million by weight
wt% = weight percent

2.3.4 Natural Gas

Natural gas is required as a backup fuel for the combustion turbine and during start-ups and shut-downs. Natural gas is also used to fuel the auxiliary boiler, flare pilots, ammonia synthesis preheater, start-up the SRU, and as support fuel for the SRU tail gas thermal oxidizer. The natural gas supply metering station will be within the Project Site, near the southwestern corner.

An interconnection with a PG&E pipeline is available to supply natural gas to the Project. The pipeline length will be approximately 13 miles. The interconnect will consist of one tap off the existing natural gas line and one metering station at the beginning of the natural gas linear adjacent to the PG&E Inlet. The metering station will be up to 100 feet by 100 feet, and will be surrounded by a

chain-link fence. In addition, there will be a metering station at the end of the natural gas linear, near the southwestern corner of the Project Site, and a pressure limiting station on the Project Site.

The estimated delivery pressure of the PG&E line is a minimum of 335 psig. The Project includes a natural gas compressor to provide sufficient pressure for start-up and natural gas operation.

Typical yearly averages for the natural gas composition and physical properties are given in Table 2-7, Typical Natural Gas Composition.

Table 2-7
Typical Natural Gas Composition

Pressure, psig	> 600
Specific Gravity	0.58
Higher Heating Value, Btu/scf	1,022
Composition, mol%	
Methane (CH_4 or C_1)	96.07
Ethane (C_2)	1.9
Propane (C_3)	0.3
iso-Butane (i-C_4)	0.05
normal Butane (n-C_4)	0.05
iso-Pentane (i-C_5)	0.02
normal Pentane (n-C_5)	0.01
Hexanes plus higher carbon compounds (C_6+)	0.03
Carbon Dioxide (CO_2)	1.08
Nitrogen (N_2)	0.46
Total Sulfur	< 0.75 grain/100 scf

Source: HECA, 2012.

Notes:
< = less than
> = greater than
Btu = British thermal units
I = iso
n = normal
psig = pounds per square inch gauge
grains/scf = grains per standard cubic foot

2.3.5 Oxygen and Nitrogen

The gasification process requires high-pressure, high-purity (99.5 volume percent) oxygen (O_2). The O_2 is supplied from the ASU, which separates and purifies O_2 and nitrogen from the ambient air. The ambient air is filtered, compressed, dried, and cooled to cryogenic temperatures. High-purity O_2 created in this process is pumped to the required pressure, vaporized, and sent to the Gasification Unit. In addition, low-pressure, high-purity O_2 is used in the SRU. The ASU also supplies high-purity, compressed nitrogen for use in the CT, the Ammonia Synthesis Unit, and

various uses within the Gasification Unit. In the CT, nitrogen is used as a diluent to reduce the thermal NO_X produced when hydrogen-rich fuel is combusted. The ASU also provides high-purity nitrogen for purging equipment, piping, and instrumentation.

2.4 PRODUCT OUTPUT

As a polygeneration facility, the Project is designed to produce several types of products. These products include the following, which are discussed below in more detail:

- Electricity;
- CO_2;
- Degassed liquid sulfur;
- Gasification solids; and
- Low-carbon nitrogen-based products.

2.4.1 Electricity and Transmission Line

A new electrical transmission line approximately 2 miles in length will be constructed to connect the Project Site with a future PG&E switching station. The power generated by the Project will be connected to the PG&E system by a new, single-tower, 230 kV transmission line. This single-circuit line will be connected to a new switchyard at the Project Site. The proposed transmission route exits the Project Site, crosses Tupman Road and runs in an easterly direction, crosses Morris Road and continues east to enter the PG&E switching station.

Table 2-8, Electrical Specification, describes the general specification for electricity delivery.

Table 2-8
Electrical Specification

Terminal Point	230-kV Plant Switchyard
Utility Interconnection Location	PG&E 230-kV Switching Station
Line Voltage	230 kV
Frequency	60 Hz
Switchyard	Outdoor Switchyard

Source: HECA, 2012.
Notes:
Hz = Hertz
kV = kilovolts

2.4.2 Carbon Dioxide

CO_2 will be compressed and transported by a new pipeline approximately 3 miles in length to the OEHI CO_2 Processing Facility, where it will be used for CO_2 EOR and sequestration in the EHOF. The CO_2 provided by the pipeline will be sequestration-ready, and will not require any additional compression or physical alteration at the OEHI Processing Facility for sequestration of the CO_2 stream. Additional compression will be used in the EOR process. Permitting of emission sources to support EOR at the receiving facilities will be undertaken separately by OEHI, and are not addressed in this application.

2.4.3 Sulfur

The selection and integration of pre-combustion capture and sulfur recovery technologies allows the Project to minimize sulfur emissions. Sulfur found in the HECA feedstock fuels is removed from the syngas by the AGR and delivered to the SRU, where it is converted into a saleable product. Unconverted, residual sulfur compounds (SRU tail gas) are recycled back into the gas treatment section for subsequent capture. Most of the sulfur will be transported by truck to off-site customers, but some may also be transported by rail. It is estimated that sulfur product export would be approximately 75 percent by truck and 25 percent by rail. The planned production rate would be 100 stpd, and Table 2-9, Sulfur Specification, describes the sulfur product specification.

Table 2-9
Sulfur Specifications

Nominal Quantity	100 stpd
Maximum Degassing Capacity	150 stpd
Quality	Commercial Grade Degassed Liquid Sulfur
Degassed H_2S Content	<10 ppmw

Source: HECA, 2012.
Notes:
< = less than
H_2S = hydrogen sulfide
ppmw = parts per million by weight
stpd = short tons per day

2.4.4 Gasification Solids

Gasification solids are comprised of the silica, alumina, and other constituents found in coal and petcoke. The high temperature in the gasifier produces a glassy, vitrified solid that is suitable for reuse. Most of the gasifier solids will be transported by rail for beneficial reuse by regional industries. A smaller portion can be transported to nearby industries by truck. It is estimated that gasification solids export would be approximately 75 percent by rail and 25 percent by truck. The planned production rate would be about 840 stpd on a dry basis. The composition of the gasification solids has been estimated based on the anticipated feedstock composition. Table 2-10, Example Composition of Gasification Solids, represents a projected composition of the gasification solids.

Gasification solids are dewatered, and the solids are accumulated for shipment. Upon exiting the gasifier, the liquids are recovered and returned for reuse in the process. The dewatered gasification solids will be retained in on-site storage until sufficient quantities are accumulated to facilitate their economical transportation. On-site gasification solids storage has the capacity for 7 days of production.

HECA has studied the beneficial reuse of gasification solids in a variety of industrial applications. Areas currently being evaluated include reuse for the production of cement, roofing granules, and sandblast grit.

Table 2-10
Example Composition of Gasification Solids

Determination	Results %
Silicon (SiO_2)	49.43
Aluminum (Al_2O_3)	16.65
Iron (Fe_2O_3)	10.71
Calcium (CaO)	17.43
Magnesium (MgO)	1.50
Sulfur (SO_3)	0.20
Sodium (Na_2O)	0.98
Potassium (K_2O)	1.80
Titanium (TiO_2)	0.78
Phosphorus (P_2O_5)	0.32
Manganese (MnO)	0.20
Carbon (C)	0.00 (below detectable)
Mercury (Hg)	0.00 (below detectable)

Source: HECA, 2012.

2.4.5 Low-Carbon Nitrogen-Based Products

The Project will produce low-carbon nitrogen-based products, including, but not necessarily limited to:

- **Ammonia.** The ammonia unit capacity is approximately 2,000 stpd, with a daily average production rate of 1,500 stpd. The ammonia is an intermediate for the on-site production of urea pastilles and UAN. The Project has been designed with flexibility to allow for the option of directly selling ammonia product, rather than using it for urea or UAN production; and it is estimated that this amount could be up to 500 tons/day. Estimated ammonia export is 25 percent by rail and 75 percent by truck.

- **Urea pastilles.** Urea pastilles are small, solid pellets of urea. The urea pastilles unit capacity is 1,720 stpd, which is also the planned production rate. Estimated urea export is 75 percent by rail and 25 percent by truck.

- **UAN**. The UAN unit capacity is 1,500 stpd, with a planned production rate of 1,400 stpd. The estimated movements are 50 percent by rail and 50 percent by truck.

2.4.6 Plant Performance Summary

Table 2-11, Representative Heat and Material Balances, presents typical heat and material balances. Table 2-12, Maximum Feeds and Products, shows the maximum feed and product rates anticipated for the Project.

Table 2-11
Representative Heat and Material Balances

Operating Case	Hydrogen-Rich Fuel		Natural Gas
	Maximum Power	Maximum Ammonia Production	
Ambient Temperature, °F	97	65 [1]	97
Feeds			
Feedstock, stpd (AR)	5,800	5,800	0
Feedstock, MMBtu/hr [HHV]	4,710	4,710	0
Natural Gas, MMBtu/hr [HHV]	0	0	2,400
Water, gpm	5,150	4,610	1,450
Products			
Hydrogen, mmscfd [2]	273	273	0
Ammonia, stpd	1,240	2,000	0
Urea Pastilles, stpd	1,700	1,700	0
Urea Ammonium Nitrate (UAN-32) Solution, stpd	1,400	1,400	0
Carbon Dioxide, stpd	9,200	9,200	0
Sulfur, stpd	100	100	0
Gasification Solids, stpd	850	850	0
Power Balance			
Combustion Turbine/Turbine, MW	405	295	320
Total Auxiliary Load, MW	138	150	20
CO_2 Compression, MW	40	40	0
AGR with Refrigeration, MW	23	23	0
NH_3 Unit Compression, MW	15	24	0
Other Internal Users, MW	60	63	20
Net Power, MW	267[3]	145	300

Source: HECA, 2012.

Notes:

[1] Ambient temperature variations have minimal effect on hydrogen-rich fuel fueled combustion turbine generator output and gasification operation. Results are nearly constant for plant output across the ambient temperature range.

[2] Hydrogen contained in the hydrogen-rich fuel used to fuel power generation equipment and production of nitrogen-based products.

[3] Based on preliminary net output. Further optimization may result in an output of up to 300 MW.

AGR = Acid Gas Removal
AR = as received
°F = degrees Fahrenheit
gpm = gallons per minute
HHV = higher heating value
IGCC = integrated gasification combined cycle
MMBtu/hr = million British thermal units per hour
mmscfd = million standard cubic feet per day
MW = megawatt
NH_3 = Ammonia
stpd = short tons per day

Table 2-12
Maximum Feeds and Products

Feeds	Maximum Amounts
Feedstock (AR)	5,800 stpd
Water (high ambient)	5,200 gpm
Products	**Maximum Amounts**
Maximum: Normal Low-Carbon Power Maximum Power Capability[1]	 265 MW 300 MW
Carbon Dioxide for EOR	9,200 stpd
Sulfur	150 stpd
Gasification Solids	850 stpd
Ammonia (planned export)	500 stpd
Urea Pastilles	1,720 stpd
Urea Ammonium Nitrate (UAN) Solution	1,500 stpd

Source: HECA, 2012.

Notes:
[1] Maximum power capacity as submitted in the CAISO Interconnection Request
AR = as received
ASU = Air Separation Unit
CAISO = California Independent System Operator
gpm = gallons per minute
MW = megawatt
stpd = short tons per day

This section discusses the expected emissions from the proposed Project. Emissions of both criteria pollutants and GHGs were estimated for each emitting source listed in Sections 3.4 and 3.5, respectively. Hazardous air pollutant emissions for each emitting source are discussed in Section 5. These emissions will be used to show that the Project will not cause an exceedance of PSD Significant Impact Level (SIL), increments, California or Federal AAQS, or significant health risk measures.

3.1 EQUIPMENT LIST

This section summarizes the specifications of all equipment that will emit air pollutants at HECA, and the controls applied to limit emissions.

Permit Unit #	Permit Unit Description
1	Combined Cycle Combustion Turbine: The Combined Cycle Power Block consists of a hydrogen-rich fuel, 405 MW gross MHI 501 GAC® G-class, air-cooled advanced combustion turbine generator (CTG), with a Heat Recovery Steam Generator (HRSG), and one condensing Steam Turbine Generator (STG) operating in combined-cycle mode. The CTG can operate on natural gas as a backup fuel. The HRSG includes a duct burner with a maximum firing rate of 360 MMBtu/hour HHV using hydrogen rich fuel and PSA off-gas, a selective catalytic reduction (SCR) system, and a carbon monoxide catalyst system.
2	Coal Dryer: Receives blended feedstock, grinds and dries it before entering the gasifier; the heat source for drying is hot turbine exhaust gas from the HRSG. The HRSG flue gas that is diverted to the coal dryer has emissions already controlled by the oxidation catalyst and SCR. The unit is equipped with a baghouse for dust collection.
3	Auxiliary Boiler: a 213 MMBtu/hour natural-gas–fired boiler equipped with low-NO_X burners and SCR.
4	Power Block Cooling Tower: 95,500 gpm Multi-cell Mechanical-draft Cooling Towers with high-efficiency drift eliminators; serving the power block.
5	Process Cooling Tower: 162,582 gpm Multi-cell Mechanical-draft Cooling Tower with high-efficiency drift eliminators; serving the Gasification Block and Process Units.
6	Air Separation Unit Cooling Tower: 44,876 gpm Multi-cell Mechanical-draft Cooling Towers with high-efficiency drift eliminators; serving the Air Separation Unit.
7	Gasification Flare: 3,000 MMBtu/hr emergency elevated flare with 0.5 MMBtu/hr natural-gas pilot, primarily serving the Gasification Block.
8	Rectisol Flare: 430 MMBtu/hr emergency elevated flare with 0.3 MMBtu/hr natural-gas pilot, primarily serving the Rectisol unit.

Permit Unit #	Permit Unit Description
9	SRU Flare: 36 MMBtu/hr emergency elevated flare with 0.3 MMBtu/hr natural-gas pilot, primarily serving the Sulfur Recovery Unit (SRU).
10	Tail Gas Thermal Oxidizer: A 13 MMBtu/hr tail gas thermal oxidizer is part of the sulfur recovery system, consisting of a Sulfur Recovery Unit (SRU), a Tail Gas Treatment Unit (TGTU), miscellaneous tanks, compressors, pumps, condensers, heat exchangers, and piping.
11	CO_2 Vent: CO_2 recovery (capture, compression, and transportation) and venting system for emergency releases of a stream of primarily CO_2 from the Acid Gas Removal Unit and the Tail Gas Treatment Unit (TGTU).
12	Standby Diesel Generator 1: 2,922 BHP Cummins Model QSK60-G6 Tier 4 certified diesel-fired emergency standby IC engine powering a 2,000 kW Cummins model DQKC electric generator (or equivalent).
13	Standby Diesel Generator 2: 2,922 BHP Cummins Model QSK60-G6 Tier 4 certified diesel-fired emergency standby IC engine powering a 2,000 kW Cummins model DQKC electric generator (or equivalent).
14	Firewater Pump: 556 BHP Cummins Model CFP-15E-F40 Tier 4 certified diesel-fired emergency standby IC engine powering a firewater pump (or equivalent).
15	Ammonia Start-Up Heater: a 55 MMBtu/hr natural-gas fired start-up heater for the Ammonia Synthesis Unit, equipped with low-NO_X burners.
16	Nitric Acid Unit: Produces up to 501 tons per day of nitric acid from ammonia oxidation, NO oxidation, and absorption. Equipped with SCR to control NO_X, and tertiary catalytic decomposition to control N_2O.
17	Urea Pastillation Unit: Produces up to 1,720 tons per day of high-quality urea pastilles; enclosed with a hood and baghouse to control particulate emissions.
18	Ammonium Nitrate Unit: Produces up to 636 tons per day of ammonium nitrate, equipped with a water-scrubbing system to control emissions of particulates.
19	Feedstock Handling System: These operations include bulk material unloading, loading, belt conveying, belt transfer points, silo loading, and feedstock crushing, all controlled with a system of 15 baghouses.
20	Fugitive emissions: These are associated primarily with the Gasification Block and the Manufacturing Complex, and will be controlled with a leak detection and repair (LDAR) program.

3.2 CRITERIA POLLUTANT BACT

Under SJVAPCD New Source Review rules, an Applicant must apply BACT to any new or modified emissions unit that has a potential to emit 2.0 pounds per day or more of any criteria pollutant. The SJVAPCD maintains a list of current BACT standards for specific source categories that is posted on the District's website.

Federal requirements pertaining to control of pollutants subject to PSD review (i.e., attainment pollutants) were promulgated by the USEPA in 40 Code of Federal Regulations (CFR) 52.21 (j), which require new major sources of air pollution to apply BACT for each regulated pollutant for which the potential to emit is significant.

Appendix B, Criteria Pollutant BACT Analysis, provides a formal BACT determination for the Project emissions of criteria pollutants. The proposed BACT levels for each Project source are shown in Table 3-1, Proposed BACT for the Project, and incorporated in the emission calculations.

Table 3-1
Proposed BACT for the Project

Pollutant	Technology	Emission Limit
CTG/HRSG Combustion Turbine (excluding Start-Up/Shut-Down conditions)		
NO_X	Diluent injection, Selective Catalytic Reduction (SCR), limited operation on natural gas	2.5 ppm NO_X @ 15 percent O_2 on hydrogen-rich fuel, 3-hour average
		4 ppm NO_X @ 15 percent O_2 on natural-gas fuel, 3-hour average
CO	GCP, CO catalyst), limited operation on natural gas	3 ppm CO @ 15 percent O_2 on hydrogen-rich fuel, 3-hour average
		5 ppm CO @ 15 percent O_2 on natural-gas fuel, 3-hour average
PM/PM_{10}	GCP, gas cleanup, gaseous fuels, pipeline-quality natural gas	15 lb/hr on hydrogen-rich fuel and natural-gas fuel
SO_2	Hydrogen-rich fuel cleanup, pipeline-quality natural gas	≤ 2 ppmv total sulfur in hydrogen-rich syngas, ≤ 10 ppmv total sulfur in PSA off-gas
		≤ 0.75 grain/100 scf (12.65 ppm for natural gas)
VOC	CO catalyst), limited operation on natural gas	1 ppm VOC @ 15 percent O_2 on hydrogen-rich fuel, 3-hour average
		2 ppm VOC @ 15 percent O_2 on natural-gas fuel, 3-hour average
NH_3	SCR	5 ppm NH_3 slip on hydrogen-rich fuel and natural-gas fuel
Coal Dryer		
PM/PM_{10}	Baghouse	0.001 grain/scf outlet dust loading

Table 3-1
Proposed BACT for the Project (Continued)

Pollutant	Technology	Emission Limit
Cooling Towers		
PM/PM_{10}	High-efficiency drift eliminators, Total Dissolved Solids limit in circulating water, and good operating practice	0.0005 percent drift as percent of the circulating water
Auxiliary Boiler, Natural Gas 213 MMBTU/hr		
NO_X	Low-NO_X burner and SCR	5 ppm NO_X @ 3 percent O_2
CO	GCP, annual tune-up	50 ppmvd @ 3 percent O_2
PM/PM_{10}	GCP, pipeline-grade natural gas fuel	0.005 lb/MMBtu heat input
SO_2		0.00285 lb/MMBtu (12.65 ppm for natural gas)
VOC		0.004 lb/MMBtu heat input
NH_3	SCR	5 ppm NH_3 slip natural-gas fuel
Emergency Diesel Engines (2 Emergency Generators; 2,922 horsepower each)		
NO_X	Certified USEPA Tier 4 diesel engine, combustion controls, restricted operating hours, low-sulfur diesel fuel	0.5 g/bhp/hr
CO		2.6 g/bhp/hr
PM/PM_{10}		0.07 g/bhp/hr
SO_2		Very-low-sulfur diesel fuel (15 ppmw or less)
VOC		0.3 g/bhp/hr
Emergency Diesel Engine (Fire Pump; 565 horsepower)		
NO_X	Certified USEPA Tier 4 diesel engine, combustion controls, restricted operating hours, low-sulfur diesel fuel	1.5 g/bhp/hr
CO		2.60 g/bhp/hr
PM/PM_{10}		0.015 g/bhp/hr
SO_2		very-low-sulfur diesel fuel (15 ppmw or less)
VOC		0.14 g/bhp/hr
Gasification Flare		
NO_X, CO, PM/PM_{10}, SO_2	GCP, gaseous fuel only, gas cleanup/limit on reduced sulfur in hydrogen-rich fuel	
VOC	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, VOC destruction of ≥ 98.5 percent	
Rectisol® Flare		
NO_X, CO, PM/PM_{10}, SO_2	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, gas cleanup/limit on reduced sulfur in syngas	
VOC	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, VOC destruction of ≥ 98.5 percent	
SRU Flare (Sulfur Recovery System)		
NO_X, CO, PM/PM_{10}	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases	
SO_2	Caustic Scrubber	

Table 3-1
Proposed BACT for the Project (Continued)

Pollutant	Technology	Emission Limit
VOC	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, VOC destruction of ≥ 98.5 percent	
Thermal Oxidizer (Sulfur Recovery System) (excluding Start-Up/Shut-Down conditions)		
NO_X	GCP	0.24 lb/MMBtu
CO		0.20 lb/MMBtu
PM/PM_{10}		0.0076 lb/MMBtu
SO_2	GCP, gas cleanup to ≤ 10 ppmv H_2S	2 lb/hr process vent gas
VOC	GCP	0.0055 lb/MMBtu
CO_2 Vent		
CO	Gas cleanup, restricted operating hours	1,000 ppmv
VOC		40 ppmv
H_2S	Acid gas removal	10 ppmv
Feedstock		
PM/PM_{10}	Dust collector, adequate moisture to prevent visible emissions in excess of 5 percent opacity	0.005 grain/scf outlet dust loading
Ammonia Plant Heater, Natural Gas 55 MMBtu/hr		
NO_X	Low- NO_X burner, limited operation	9 ppm NO_X @ 3 percent O_2
CO	GCP, annual tune-up	50 ppmvd @ 3 percent O_2
PM/PM_{10}	GCP, pipeline-grade natural gas fuel	0.005 lb/MMBtu heat input
SO_2		0.00285 lb/MMBtu (12.65 ppm for natural gas)
VOC		0.004 lb/MMBtu heat input
Urea HP Absorber		
NH_3	Wet scrubber	11.1 lb/hr
Urea LP Absorber		
NH_3	Wet scrubber	2.0 lb/hr
Urea Pastillation		
PM/PM_{10}	Baghouse	0.001 grain/dscf
Nitric Acid Plant		
NO_X	SCR	0.2 lb/ton (15 ppmv in vent gas)
NH_3	SCR	5 ppm NH_3 slip

Table 3-1
Proposed BACT for the Project (Continued)

Pollutant	Technology	Emission Limit
Ammonium Nitrate Plant		
PM/PM_{10}	Wet scrubber	0.2 lb/hr
Fugitives		
VOC	LDAR, leak detection for valves and connectors with VOC > 100 ppmv above background, and for pumps and compressor seals with VOC > 500 ppmv above background	Varies

Source: HECA 2012.

Notes:
BACT = best available control technology
CO = carbon monoxide
CTG = combustion turbine generator
FGR = flue gas recirculation
GCP = good combustion practice
LDAR = leak detection and repair
MMBtu = million British thermal units
NH_3 = ammonia
NO_X = nitrogen dioxide
O_2 = oxygen
PM/PM_{10} = particulate matter/particulate matter less than 10 microns
ppm = parts per million
ppmvd = parts per million volumetric dry
scf = standard cubic feet
SCR = selective catalytic reduction
SO_2 = sulfur dioxide
VOC = volatile organic compound

3.3 GREENHOUSE GAS BACT

The PSD air permit regulations (40 CFR 52.21 [j]) require new major sources of air pollution to apply BACT for each "regulated pollutant" for which the potential to emit is significant. Starting in 2011, the USEPA Greenhouse Gas Tailoring Rule requires proposed new projects with carbon dioxide equivalent (CO_2e) emissions greater than 75,000 tons per year (tpy) and GHGs on a mass basis greater than 100 tpy (for steam electric generating units [EGUs]) to demonstrate the use of BACT for their GHG emissions in the pre-construction permit review. The HECA Project emissions will exceed these thresholds; therefore, a GHG BACT analysis has been prepared for the Project's PSD permit application.

The Project will produce low-carbon baseload electricity and nitrogen-based products by capturing CO_2 from the produced syngas and transporting it for EOR and sequestration, thus controlling GHG emission to levels substantially below that of other fossil-fuel power plants. A full GHG BACT determination for the Project is provided in Appendix C, Greenhouse Gas BACT Analysis. Table 3-2 summarizes the GHG BACT findings for all Project emission sources.

Table 3-2
Summary of Proposed GHG BACT Permit Limits for HECA

Equipment	BACT Determination	Proposed GHG-Specific BACT Limit	Relevant SJVAPCD Permit Limits
HECA Project (entire facility)	Energy efficient facility design, plus controls listed below.	535,278 tonnes of CO_2e per year	No equivalent SJVAPCD Permit Limit
Combustion Turbine	Hydrogen-rich fuel Firing: Pre-combustion capture of CO_2 Natural Gas Backup: Limited Operation	Capture 90 percent of carbon in syngas (as monitored through CO_2 content in hydrogen-rich fuel and captured CO_2 stream). CO_2 power related emissions to ≤ 400 lb/MWh (based on SB 1368).	Fire only hydrogen-rich fuel and PSA off-gas, and natural gas as backup fuel. Hourly, daily, and annual limits on NO_X, VOC, CO, PM_{10}, SO_X. Monitor fuel consumption.
CO_2 Recovery System and Vent	Compression and Transport CO_2 to EOR Good Operating Practices Limited Operation	No additional limits required beyond air permit.	Venting only when compression, transportation, or injection system is unavailable and during gasifier start-up and shut-down. Flow measurement. Concentration, hourly, and annual limits on CO, VOC, H_2S and COS
Auxiliary Boiler	Use of gas fuels, Energy-Efficient Design, process heat integration, Limited Operation, Periodic Tuning	Boiler tuning and limits from air permit.	Fire only natural gas. Total annual heat input limited to 466 billion Btu and monitor fuel use.
Thermal Oxidizer	Good Operating Practices	No additional limits required beyond air permit.	Annual operating limits.
Gasification, SRU and Rectisol® Flares	Good Operating Practices, Flare Minimization Plans, Limited Operation	No additional limits required beyond air permit.	Flare Minimization Plan, total flow monitors, annual operating limits.
Nitric Acid Unit	Tertiary Control (Catalytic Decomposition)	N_2O emissions of 0.32 lbs N_2O/ton HNO_3, based on an annual average demonstrated with testing.	Annual operating limits.
Ammonia Synthesis Plant Start-up Heater	Good Operating Practices, Natural Gas Fuel, Limited Operation	No additional limits required beyond air permit.	Fire only natural gas. Total annual heat input limited to 7,700 MMBtu and monitor fuel use.
Urea Absorber Vents	Good Operating Practices	No additional limits required beyond air permit.	Annual operating limits.
Equipment Fugitive Leaks	No further controls	No additional limits required beyond air permit.	LDAR on select process areas

Table 3-2
Summary of Proposed GHG BACT Permit Limits for HECA (Continued)

Equipment	BACT Determination	Proposed GHG-Specific BACT Limit	Relevant SJVAPCD Permit Limits
Emergency Engines	Good Operating Practices	No additional limits required beyond air permit.	50 hours non-emergency operation per year for electric generators; 100 hours non-emergency operation per year for firewater pump
Circuit Breakers	Enclosed pressure SF_6 circuit breakers with leak detection	Use of enclosed pressure SF_6 circuit breakers with leak detection.	No SJVAPCD Permit Limits

Notes:
BACT = Best Available Control Technology
Btu = British thermal unit
CO = carbon monoxide
CO_2 = carbon dioxide
COS = carbonyl sulfide
CTG = combustion turbine generator
GHG = greenhouse gas
HRSG = heat recovery steam generator
LDAR = leak detection and repair
NO_X = nitrogen oxides
PM_{10} = particulate matter less than or equal to 10 microns in diameter
SF_6 = sulfur hexafluoride
SJVAPCD = San Joaquin Valley Air Pollution Control District
SO_X = sulfur oxides
SRU = sulfur recovery unit
VOC = volatile organic compound

3.4 CRITERIA POLLUTANT EMISSIONS

The Project is an IGCC polygeneration project that will produce low-carbon baseload electricity, low-carbon nitrogen–based products in an integrated Manufacturing Complex, and CO_2 for EOR. The Gasification Block will feature an MHI oxygen-blown dry-feed gasifier, Shift, LTGC, Mercury Removal, AGR, Sulfur Recovery, Tail Gas Treating, EOR CO_2 Compression Units, and associated utilities to produce hydrogen-rich fuel. Sulfur and mercury components will be removed, and CO_2 will be captured and compressed for EOR and resulting sequestration.

The Combined Cycle Power Block will generate approximately 405 MW of gross power, and will provide approximately 300 MW output of low-carbon baseload electricity. The Power Block will feature one MHI 501 GAC® CTG that will be fueled with hydrogen-rich fuel from the gasification plant, and natural gas as a backup fuel; an HRSG with duct firing on a combination of hydrogen-rich fuel and PSA off-gas; and a condensing steam turbine-generator.

The Manufacturing Complex is an integrated complex that will produce approximately 1 million tons per year of nitrogen-based products, including urea, UAN, and anhydrous ammonia, to be used in agricultural, transportation, and industrial applications. Process units used in producing the low-carbon, nitrogen-based products are the PSA, Carbon Dioxide Purification, and

Compression, Ammonia Synthesis, Urea, Urea Pastillation and Storage, Nitric Acid, Ammonium Nitrate, Urea Ammonium Nitrate Units, and associated utilities.

The operational emissions from the Project are mainly generated from the combustion of the hydrogen-rich fuel in the Combined Cycle Power Block. Other emission sources are outlined below. Each emission source can be categorized as part of the Power Block, Gasification Block, Manufacturing Complex, or ancillary equipment as shown below.

Power Block	Gasification Block	Manufacturing Complex	Ancillary Equipment
• Combustion Turbine (MHI 501GAC®) • Power Block Cooling Tower	• Coal Dryer • Auxiliary Boiler • Gasification Flare • Sulfur Recovery Unit (SRU) Flare • Rectisol® Flare • Tail Gas Thermal Oxidizer • ASU and Process Cooling Towers • CO_2 Vent • Material Handling Dust collection (Feedstock)	• Nitric Acid Unit • Urea Absorbers • Urea Pastillation • Ammonium Nitrate Unit • Ammonia Synthesis Unit Start-Up Heater • Material Handling Dust collection (Urea)	• Two Emergency Diesel Generators • Emergency Diesel Firewater Pump

3.4.1 Plant Start-Up

This section describes a typical plant-wide start-up that would occur after the commissioning phase. The commissioning and initial start-up of the facility is described later in the commissioning section. HECA LLC anticipates that one to two plant start-ups/shut-downs will be necessary for annual maintenance. This sequence assumes that all the necessary utility and support systems are already in service (plant-distributed control system, fire protection and other safety systems, electrical switchyard and in-plant electrical distribution, water treatment, natural gas, steam, instrument and plant air, purge nitrogen, etc.).

The IGCC takes 4 to 6 days from cold start to export of low-carbon power. The following summarizes the start-up sequences. Note that if the IGCC is being restarted after a short outage, when the equipment is still close to operating conditions, the durations of each step will be much shorter than indicated

3.4.1.1 Air Separation Unit Start-Up

The ASU will require 3 to 4 days to start up and reach full capacity. Because the ASU operates at cryogenic conditions, the start-up sequence includes an extensive cool down and drying period. During this time, the main air compressor and booster air compressor will be operated to provide the auto refrigeration necessary to cool and dry the ASU. Near the end of the start-up sequence, the ASU will begin producing liquid oxygen (LOX) and liquid nitrogen. The LOX is stored to provide a backup oxygen supply to cover a compressor trip or other short ASU outage.

The liquid nitrogen storage is provided as a backup supply for the purge nitrogen system. Once the ASU is producing enough oxygen to operate the gasifier, the LOX pumping and vaporization system can be started to make high-pressure oxygen vapor available to the Gasification Unit.

3.4.1.2 AGR Start-Up

The AGR Unit is assumed to be ready to start (purged with nitrogen and with start-up methanol levels established in the circulating system). Methanol circulation is started and the refrigeration system is started to begin cooling the methanol to operating temperature (approximately minus 40°F). This sequence is expected to take about 2 days, and will complete at about the same time that sufficient oxygen is available to start the gasifier.

3.4.1.3 SRU Start-Up

The SRU is a single train with an oxygen-enriched reaction furnace (thermal reactor) and two modified Claus reactor stages. The SRU reaction furnace is refractory lined. After an extended outage, both the refractory and the SRU catalyst require a gradual heating program that will take about 3 days for initial curing and dryout, and 1 day on subsequent start-ups. The heating is provided by firing natural gas with air in the reaction furnace. The combustion products flow through the reaction furnace, catalyst beds, and boilers to the tail gas thermal oxidizer. During the refractory dryout/cure period, the hydrogenation reactor in the TGTU will also be preheated. The hydrogenation reactor catalyst requires pre-sulfiding prior to being put into operation, which will be timed to complete when the SRU is feed-ready and the gasifier is feed-ready.

3.4.1.4 Gasification Block Start-Up

The MHI gasifier is a dry-feed system and the gasification reaction zone is protected by a membrane wall. This design reduces the amount of time needed to warm the gasifier (as compared to a refractory-lined vessel) when preparing the gasifier for start-up. Natural gas will be burned in air inside the gasifier to provide heat during initial warm-up, and will be sent to the gasification flare.

Once the gasifier is up near operating temperature, the natural gas will be partially oxidized with O_2, which makes a low-sulfur syngas. The pressure and flow is then ramped up to allow the start-up of the shift/LTGC and Rectisol® units. Initially, the unshifted syngas will be sent to the gasification flare. Once the shift reactors are functioning, the shifted syngas will be sent to the gasification flare. The venting location will then be moved downstream of the Rectisol® absorber, and hydrogen-rich fuel will go to the gasification flare. The flaring will continue during the gasifier's transition from natural gas to coal/coke until the hydrogen-rich fuel can be sent to the gas turbine.

The shift reactors require warm-up and pre-sulfiding before sour syngas (containing hydrogen sulfide) can be introduced. The shift reactor catalyst is heated by circulating hot nitrogen across the catalyst beds for about 2 days. The nitrogen is heated indirectly with a high-pressure steam heater. Once the catalyst is hot, a small amount of sulfur-containing compound is added to the circulating nitrogen. The pre-sulfiding is completed when traces of sulfur are detected in the

effluent of the second shift reactor. The shift reactors are then placed in a hot standby condition and ready for feed.

The CO_2 compression system will be purged and ready to compress CO_2. The CO_2 compressor start-up sequence will be timed to coincide with the time the AGR Unit is producing CO_2 in sufficient quantity to allow sustained operation of the CO_2 compressor.

When the gasifier reaches operating temperature, and the gasifier system has been purged with nitrogen, the gasifier can be started by introducing oxygen to gasify the natural gas, then switching to the coal/petcoke-blend feedstock. Produced raw syngas is sent to Gasification Flare until the system pressure and flow are stabilized. During start-up, the syngas sent to flare is either produced from natural gas or treated in the AGR Unit, and will be essentially sulfur-free.

Syngas is diverted through the shift reactors and LTGC sections, and then to the AGR Unit. The circulating solution in the AGR Unit then begins absorbing the CO_2 in the syngas. Once the CO_2 concentration in the rich solution reaches the required level, the flash drums will begin separating CO_2 vapor. This CO_2 will be washed to remove any traces of methanol, and vented at the Rectisol® flare until the flow rate is increased, and then vented through the CO_2 vent.

Once sufficient hydrogen-rich fuel production is available, the MHI 501 GAC® combustion turbine can initiate a switch to 100 percent hydrogen-rich fuel. At this point, the gasifier start-up is complete and operation begins.

Also at this point, the start-up of the PSA and Ammonia Plant is initiated—a process that takes 1 to 2 days. Subsequently, the Urea Plant start-up is initiated over a second 24-hour process.

3.4.1.5 Power Block Start-Up

The MHI 501 GAC® and the MHI steam turbine are on a common shaft, with the common generator located between the CT and ST. A clutch is provided between the ST and the generator to allow the CT to start-up independently of the ST. The clutch is disengaged during the following CT start-up sequence.

Once all the start-up permissives are met, the MHI 501 GAC® CT start signal is given and the generator is used as a motor to rotate the CT and accelerate it until the operation is self-sustaining (static start). The CT compressor is first partially loaded to provide enough air flow and duration to purge the HRSG. Following the purge, natural gas is introduced into the CT combustors, resulting in the CT operation becoming self-sustaining, and the discontinuation of the static start. Natural gas is required to start up the combustion turbine. When the combustion turbine reaches 3,600 revolutions per minute (RPM), or “full speed, no load,” it is synchronized with the electrical grid, and the main breaker is closed. Shortly after the CT is synchronized, it is loaded to a minimum, or “spinning reserve” load. All the preceding steps are executed automatically by the CT’s control computer system. At this point, the HRSG begins warming up and rapidly begins to produce steam. The steam is initially vented; and, as pressure builds in the steam system, the atmospheric vents close and the steam flow is diverted to the surface condenser. Once dry, superheated steam is available at the ST, the ST start-up sequence can be initiated. The ST can then be accelerated to 3,600 RPM to match speed with the generator shaft.

Once the speeds are synchronized, the clutch can be engaged, and both the CT and the ST will supply shaft work to the generator. The steam turbine metal temperatures determine how quickly the steam turbine can be loaded. The cold-start sequence requires the CT to operate at reduced load (below the emission compliance level) for up to 4 hours. During this time, the CT load is slowly increased to match the steam temperature to the ST metal temperature to heat the ST while minimizing thermal stress. Once the CT reaches the required load, steam is introduced to control NO_X formation. Once the SCR catalyst reaches the required temperature, ammonia injection is initiated, and the HRSG stack emissions will fall to the required compliance levels. The CT can then be loaded normally to base load, and the ST will reach a load based on the available steam.

3.4.1.6 Ammonia Synthesis Unit Start-Up

The Ammonia Synthesis Unit will require about 2 days to start up, and reach full capacity for a cold start-up. First, the circulation of high-pressure boiler feedwater through the waste heat boiler—and that of cooling water through the appropriate heat exchangers—is started. Then, the syngas compressor is started up, and its speed slowly increased with hydrogen and nitrogen feeds. The initial period is used for purging the system and venting the gas (essentially hydrogen and nitrogen) via the flare system in the IGCC complex. The synthesis loop pressure is increased by increasing the compressor speed and syngas flow rate. The start-up heater is switched on to raise the converter catalyst bed temperatures. As the catalyst bed temperature is increased, the exothermic ammonia synthesis reaction starts taking place and ammonia is produced. As the synthesis loop pressure and the converter temperatures are increased, the ammonia refrigeration compressor is brought on line. The chilling provided by this system is used to separate the ammonia product from the main gas stream. The unconverted gas is recycled back to the syngas compressor.

The operating temperatures of the ammonia synthesis converter and the ammonia chillers are next optimized. The start-up heater is then shut down. Then, the synthesis loop pressure is brought to design conditions by increasing the syngas compressor speed and feed rates. At this point, the Ammonia Synthesis Unit is operating at its design capacity and producing cold liquid, warm liquid, and vapor ammonia product streams.

3.4.1.7 Urea Unit Start-Up

For a cold-start up, the Urea Unit will require about 18 hours to reach full capacity. First, the circulation of cooling water through the appropriate heat exchangers is started. The CO_2 Compressor and the Air Blower are then brought on line at low speed, and the CO_2 and air are circulated through the following high pressure vessels:

- High Pressure (HP) Stripper
- Urea Reactor
- HP Carbamate Condenser
- HP Scrubber

The initial period is used for purging the system and venting CO_2 at the urea absorber stacks. Then, the CO_2 compressor speed is increased and the above mentioned vessels are pressurized

with CO_2. Medium-pressure (385 psig) steam is then introduced in the HP Stripper to raise the temperature of the system. Steam condensate from the HP Stripper is flashed at low pressure (60 psig) to provide steam for users at this level.

Pressurized liquid ammonia stream is introduced into the Urea Reactor to react with the CO_2 stream. The liquid product stream from the Urea reactor consists of urea, carbamate, water, and excess ammonia. This liquid stream is routed to the HP Stripper, where carbamate and excess ammonia are separated and recycled to the Urea Reactor with the incoming CO_2 feed stream. The bottoms product from the HP Stripper is urea solution containing over 50 weight percent urea. The urea solution is routed to downstream units for further concentration. A 70 weight percent urea solution is first produced in the LP Rectifier and the Flash Vessel. This solution is stored in the intermediate solution tank. From this tank, it is pumped to the vacuum separators/ evaporators to produce either the 80 weight percent urea stream for use in the UAN complex, or a greater than 99 weight percent urea melt stream for use in the Pastillation Unit.

3.4.1.8 UAN Unit Start-Up

From a typical cold-start up, the UAN Unit will require about 12 hours to reach full capacity. The UAN Unit consists of a Nitric Acid Unit, Ammonium Nitrate Unit, and a UAN blending unit. It is assumed that both the upstream Ammonia Unit and the Urea Unit are operating normally before the UAN Unit is started up. The start-up sequence will consist of the following:

- Start-up of the Nitric Acid Unit;
- Start-up of the Ammonium Nitrate Unit; and
- Start-up of the Urea Ammonium Nitrate Blending Unit.

3.4.1.9 Start-Up of the Nitric Acid Unit

Circulation of boiler feedwater is first started through the Waste Heat Boiler. Then, the air compressor is started up and air is used to pressurize the system, consisting of the Ammonia Converter, Tail Gas Heater, Absorber, and all associated heat exchangers. The ammonia vapor stream from the battery limits is then slowly introduced and fed to the Ammonia Converter. A highly exothermic reaction of ammonia with air takes place over platinum catalyst to produce a mixture of NO and water vapor. The resulting high-temperature gas from the Ammonia Converter then flows through a heat recovery system consisting of Expander Gas Heater, Waste Heat Boiler, Tail Gas Heater, and Air Heater. The cooled gas is then routed to the Absorber, where it is mixed with air to reoxidize the NO to NO_2. The vapor stream is contacted with feedwater in the Absorber column to produce nitric acid of the desired strength. The overhead from the Absorber is tail gas, which is heated in a series of exchangers before being routed to the Tail Gas Expander for power recovery. The tail gas is treated in a catalytic system for NO_X emission control before being vented. The nitric acid product is routed to the Nitric Acid Surge tank for use as feed to the Ammonium Nitrate Unit.

3.4.1.10 Start-Up of the Ammonium Nitrate Unit

The feeds for the Ammonium Nitrate Unit are nitric acid and ammonia vapor. Ammonium Nitrate (75 to 83 weight percent) is produced in the Neutralizer by the reaction between

ammonia vapor and nitric acid. The ammonia vapor is mixed with the nitric acid with a sparger system in the bottom of the Neutralizer.

The heat of reaction in the Neutralizer boils off steam that passes overhead in the Scrubber. The function of the scrubber is to condense the right amount of steam to control the concentration of the product ammonium nitrate solution from the Neutralizer. The overhead vapors from the Neutralizer/Scrubber are further cooled and scrubbed of residual ammonia in the vent scrubber before being vented. The collected condensate is returned to the Absorber. The resultant ammonium nitrate solution is routed to the UAN Blending facility.

3.4.1.11 Start-Up of the UAN Blending Unit

The feeds to this unit are 80 weight percent urea solution from the Urea Unit and the ammonium nitrate solution from the Ammonium Nitrate Unit. These two streams are blended in the UAN Mix Tank to produce the UAN solution.

3.4.2 Operating Emissions

This section describes steady-state operations, and the start-up/shut-down operations and associated emissions from each source at HECA. A detailed description of the sequence of actions that will be taken to bring all plant components on line during a plant-wide start-up is provided in the previous section. The emissions from all HECA sources will be minimized through implementation of BACT, as outlined in Sections 3.2 and 3.3.

3.4.2.1 Power Block CTG/HRSG

The most significant emission source of the Project will be the CTG/HRSG train. The MHI 501 GAC® CT/ST generator will provide approximately 405 MW gross output to produce approximately 300 MW of reliable, low-carbon baseload electricity. Exhaust gas from the turbine section is ducted through the HRSG to generate high-energy steam, which produces additional electricity in the steam turbine. Some of the exhaust gas is also ducted from the HRSG to the Gasification Block to dry the feedstock, and will be discharged at the coal-dryer stack in that process block. Remaining exhaust gas at the HRSG is discharged through the HRSG stack. The combustion system is designed for operation on hydrogen-rich fuel. The combustion system is also equipped with separate fuel nozzles for natural-gas firing during start-up, shut-down, and equipment outages. The combustion system is designed to achieve low-NO_X emissions while injecting nitrogen diluent and combusting hydrogen-rich fuel. When operating on natural gas, water is injected for NO_X control, in addition to SCR. Natural gas is used during start-up and shut-down of the combustion turbine and during periods of unplanned equipment outages (up to 2 weeks per year).

The combustion turbine exhaust gas, supplemental hydrogen-rich fuel for duct-firing, and PSA off-gas for duct-firing are used as energy input into the HRSG. An SCR system is installed in the HRSG to reduce emissions of NO_X to meet BACT requirements. An oxidation catalyst is also installed in the HRSG to reduce CO and VOC emissions to achieve BACT levels for these pollutants. The HRSG stack is provided with a CEMS to verify compliance with applicable air

permit requirements. The CTG/HRSG will operate in a compliance load range of 70 to 100 percent.

3.4.2.2 Coal Dryer

The MHI gasification system includes equipment to grind and dry the feedstock. The blended feedstock is stored in silos. The feedstock then flows to the grinding mills, where the particle size is reduced to that required for transport into the gasifier and simultaneously dried. The heat source for feedstock drying is hot turbine exhaust gas from the HRSG. After drying the feedstock, the drying gases flow through a dust collection system, then to the atmosphere. The dried feedstock flows to intermediate storage bins, from which it is transported into the gasifier.

3.4.2.3 Power Block CTG/HRSG and Coal Dryer Operating Emissions

During operations and some phases of the start-up and shut-down activities, a portion of the HRSG flue gas will be diverted to the feedstock drying area, filtered through a baghouse, then exhausted from the coal-dryer stack. As a result, the emissions from the HRSG and coal-dryer stacks are interconnected. The HRSG flue gas that is diverted to the coal dryer has emissions already controlled by the oxidation catalyst and SCR. The exhaust stream through the coal-dryer stack is further controlled with a baghouse before being exhausted to the atmosphere.

Maximum short-term operational emissions from the CTG/HRSG and coal dryer were determined from a comparative evaluation of potential emissions corresponding to on-peak and off-peak operating conditions. The criteria pollutant emission rates were provided by the turbine vendor and the design engineers for two load conditions (on-peak and off-peak), and for each of three ambient temperatures (39ºF, 65ºF, and 97ºF) when firing syngas, and one load condition (off-peak) when firing natural gas. The maximum short-term operational emissions (in lb/hr) from the CTG/HRSG and coal dryer when combusting syngas, and from the CTG/HRSG when operating on natural gas, are presented in Table 3-3. Emissions for all operating cases are presented in Appendix D, Operational Criteria Pollutant Emissions.

The long-term operational emissions (in tons/year) from the CTG/HRSG and coal dryer were estimated by summing the emissions contributions from on-peak operating conditions, including duct-firing (for the average ambient condition of 65ºF), CTG/HRSG start-up/shut-down conditions, and maximum natural gas usage. These annual emissions of air pollutants for the CTG/HRSG and coal dryer have been calculated based on the expected operating schedule of 8,000 hours of operations, two start-ups and shut-downs per year, and 2 additional weeks of natural-gas operations other than start-up and shut-down events. The annual emissions are presented in Table 3-4.

Table 3-3
Maximum Short-Term Emissions From CTG/HRSG And Coal Dryer Stack During On-Peak Operations

Pollutant	CTG/HRSG Emissions lb/hr	Coal Dryer Emissions lb/hr	Basis	CTG/HRSG Emissions Basis (ppmv)	CTG/HRSG Emissions lb/hr	CTG/HRSG Emissions Basis (ppmv)
	Hydrogen-Rich Fuel			Natural Gas		
NO_X	25.0	4.4	Case 1 (ON Peak, 97°F Ambient)	2.5	34.1	4
CO	18.3	3.2	Case 1 (ON Peak, 97°F Ambient)	3	26.0	5
VOC	3.5	0.6	Case 1 (ON Peak, 97°F Ambient)	1	5.9	2
$PM_{10}/PM_{2.5}$	12.9	1.4	Case 3 (ON Peak, 39°F Ambient)	15 lb/hr	15.0	15 lb/hr
SO_2	4.1	0.9	Case 2 (OFF Peak, 97°F Ambient)	2 ppmv total sulfur in syngas, 10 ppmv sulfur in PSA Off-gas	4.7	12.65 ppm sulfur in natural gas
NH_3	18.5	3.2	Case 1 (ON Peak, 97°F Ambient)	5 ppmv ammonia slip	15.8	5 ppmv ammonia slip

Source: HECA, 2012.
Notes:
Emissions include duct burner operations with syngas and PSA off-gas.
Coal dryer PM emissions controlled to 0.001 gr/dscf by baghouse
gr/dcsf = grain per dry standard cubic feet
CTG/HRSG = Combustion turbine generator/heat recovery steam generator
ppmv = parts per million by volume
NO_X = nitrogen oxides
CO = carbon monoxide
VOC = volatile organic compounds
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
SO_2 = sulfur dioxide
NH_3 = ammonia
°F = degrees Fahrenheit
lb/hr = pound per hour

Table 3-4
CTG/HRSG and Coal Dryer Maximum Annual Operation Emissions

Pollutant	CTG/HRSG, tons/year				Coal Dryer, tons/year		
	Start-Up/ Shut-Down	Operations	Natural Gas Operations	Total	Start-Up/ Shut-Down	Operations	Total
NO_X	4.34	99.6	5.73	109.7	0.54	16.9	17.4
CO	15.7	72.8	4.36	92.9	0.91	12.4	13.3
VOC	0.49	13.9	1.00	15.3	0.04	2.4	2.4
$PM_{10}/PM_{2.5}$	0.82	51.3	2.52	54.6	0.05	5.6	5.6
SO_2	0.147	16.2	0.80	17.1	0.02	2.7	2.8
NH_3	0.00	73.6	2.65	76.3	0.00	12.5	12.5

Source: HECA, 2012.
Notes:
CO = carbon monoxide
CTG/HRSG = Combustion turbine generator/heat recovery steam generator
NH3 = ammonia
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
SO_2 = sulfur dioxide
VOC = volatile organic compounds

3.4.2.4 CTG/HRSG Start-Up and Shut-Down Emissions

Because start-up and shut-down events typically have higher emission rates than normal operating conditions, they are incorporated into the short- and long-term emissions estimates for the CTG/HRSG for modeling purposes. The CTG will initially be started up using natural-gas fuel, then shifted to syngas as the syngas becomes available. Conversely, during a shut-down, the CTG will be operated on syngas until production decreases, then the CTG will be operated on natural gas. Therefore, the expected emissions and durations of start-up and shut-down events summarized in Table 3-5 reflect the emissions from both natural gas and syngas combustion.

Because hours that include start-up and shut-down events will have higher NO_X, CO, and VOC emissions than the normal operating condition with fully functioning SCR and CO oxidation catalyst, these events were incorporated (as applicable) into the worst-case short- and long-term emissions estimates in the air quality dispersion modeling simulations for these pollutants.

3.4.2.5 Power-Block, ASU, and Process Cooling Towers

Power-block heat rejection will consist of a steam surface condenser, cooling tower, and cooling water system. The heat rejection system receives exhaust steam from the low-pressure steam turbine and condenses it to water for reuse. Approximately 95,500 gallons per minute (gpm) of water will be circulated in the power-block cooling tower.

Table 3-5
CTG/HRSG and Coal Drying Stack Emissions During Start-Up and Shut-Down

CTG/HRSG Start-Up							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. CTG ignition and synchronization, 20 percent load on natural gas	0.5	lb/hr	2.1	67.1	2270	15.0	65
		lb	1.0	33.6	1135	7.5	32.4
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	2.4	107.2	1044	13.1	13
		lb	4.8	214	2088	26.3	26.8
3. CTG fuel change-over, 40 percent load on syngas, start-up PSA/ammonia/urea units	50	lb/hr	2.4	66.6	81	13	4.6
		lb	120	3329	4052	657	232
Tons/Start-Up			**0.06**	**1.79**	**3.64**	**0.35**	**0.15**
Coal Drying Start-Up							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	0.3	15.1	147.4	0.9	1.9
		lb	0.7	30.3	294.7	1.9	3.8
3. CTG fuel change-over, 40 percent load on syngas	50	lb/hr	0.3	9.4	11.5	0.9	0.7
		lb	16.9	470	573	47	33
Tons/Start-Up			**0.01**	**0.25**	**0.43**	**0.02**	**0.02**

Table 3-5
CTG/HRSG and Coal Drying Stack Emissions During Start-Up and Shut-Down

CTG/HRSG Shut-Down							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea unit shut-down; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	2.4	66.6	81.0	13	4.6
		lb	9.6	266	324	52.6	18.5
2. CTG fuel change-over, 40 percent load on natural gas, gasifier depressurization	3	lb/hr	2.7	122	1191	15.0	15.3
		lb	8.2	367	3574	45.0	45.9
3. Minimum plant load, 20 percent load on natural gas	2	lb/hr	2.1	67.1	2270	15.0	64.8
		lb	4.2	134	4539	30.0	129.7
Tons/Shut-Down			**0.01**	**0.38**	**4.22**	**0.06**	**0.10**
Coal Drying Shut-Down							
Step	**Duration (hours)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea plant shut-down; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	0.3	9.4	11.5	0.9	0.7
		lb	1.4	37.6	45.8	3.8	2.6
Tons/Start-Up			**0.00**	**0.02**	**0.02**	**0.00**	**0.00**

Source: HECA, 2012.
Notes:
Basis: Start-up/shut-down procedures provided by MHI.
Coal drying starts at Step 2, above.
$PM_{10}/PM_{2.5}$ emission rate based on 0.001 grain/dscf
CTG/HRSG = Combustion turbine generator/heat recovery steam generator
NH_3 = ammonia
PSA = Pressure Swing Adsorption
NO_X = nitrogen oxides
CO = carbon monoxide
VOC = volatile organic compounds
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
SO_2 = sulfur dioxide

The ASU cooling tower is located in the ASU unit near the cooling loads. The ASU cooling tower has separate pumps and piping systems, and is operated independently of the other cooling water systems. The ASU cooling tower circulation rate is approximately 45,000 gpm.

The major heat rejection duties associated with the process cooling tower are from the CO_2 compressor and the AGR refrigeration unit. Cooling water is also supplied to the Gasification, Shift, LTGC, SRU/TGTU, SWS, and Manufacturing Complex, as well as other miscellaneous users. The process cooling tower is next to the power-block cooling tower. Each tower has a separate cooling-water basin, pumps, and piping system, and operates independently. The process tower circulation rate is about 163,000 gpm.

The cooling water circulates through each of the mechanical draft-cooling towers, which use electric-motor–driven fans to move the air into contact with the flow of the cooling water. The heat removed in the condenser will be discharged by heating the air, and through evaporation of some of the cooling water. Maximum drift, the fine mist of water droplets entrained in the warm air leaving the cooling tower, will be limited to 0.0005 percent of the circulating water flow by use of an efficient drift eliminator.

For the Power Block and process cooling towers, circulating water could range from 3,000 to 9,000 parts per million (ppm) total dissolved solids (TDS), depending on makeup water quality and tower operation. Therefore, particulate matter 10 microns in diameter or less (PM_{10}) emissions would vary proportionately. For emission calculation purposes, it is assumed that 9,000 ppm TDS are in the circulating cooling water. The cooling equipment in the ASU requires significantly lower dissolved solids in the circulating water than the rest of the plant; thus, a maximum of 2,000 ppm TDS is assumed in the circulating ASU cooling water.

The cooling tower total PM emissions are based on the maximum expected total dissolved solids in the cooling water, annual circulating water rate, and the use of a high-efficiency drift eliminator. It is conservatively estimated that 100 percent of the PM emitted from the cooling tower will be PM_{10}, and 60 percent of the PM_{10} emissions will occur as particulate matter 2.5 microns in diameter or less ([$PM_{2.5}$]; a fraction or ratio of 0.6). The basis for the ratio used is described in Response to Data Request 18 (URS, 2009b), and also in "Applicant Comments On The Preliminary Determination Of Compliance For The Hydrogen Energy California (HECA) Project (08-AFC-8)," which is provided in Appendix E, Responses to $PM_{2.5}$ Cooling Tower Data Requests from CEC and USEPA.

Annual emissions from the Power Block, ASU and process cooling tower are presented in Table 3-6 (in Section 3.4.2.18), along with the annual emissions from all sources at HECA. Hourly and annual emissions and calculation details are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.6 Auxiliary Boiler

The auxiliary boiler will provide steam to facilitate CTG start-up and for other industrial purposes. The auxiliary boiler will be designed to burn pipeline-quality natural gas at the design maximum fuel flow rate of 213 MMBtu/hour (HHV). Its emissions are based on an annual capacity factor of 25 percent maximum load operation, or 466 billion Btu per year.

The NO_X emissions from this boiler will be controlled by the installation of SCR. The NO_X emissions are based on 5 parts per million volumetric dry (ppmvd) at 3 percent O_2 with SCR. Emissions of CO are based on an exhaust concentration of 50 ppmvd at 3 percent O_2. Ammonia slip emissions are estimated based on 5 ppmvd at 3 percent O_2. SO_2 emissions are calculated based on the sulfur content of the natural gas. PM_{10}, $PM_{2.5}$, and VOC emissions are based on vendor-supplied emission factors.

A summary of auxiliary boiler emissions is presented in Table 3-6. Detailed emissions calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.7 Gasification, SRU, and Rectisol® Flares

During gasifier start-up, unprocessed/vent gas is vented to the flaring system. The Gasification Block will operate a gasification flare to safely dispose of gases during gasifier start-up and unplanned power plant upsets or equipment failures. The gasification flare may operate up to 28 hours per year for start-up and shut-down events.

There will be an SRU flare installed to safely dispose of gas emissions from the AGR source during start-up (after passing through a scrubber), or to oxidize gas releases during emergency or upset events. The SRU flare may combust such gas streams for up to 40 hours per year during plant start-ups.

The Rectisol® flare will be used to safely dispose of low-temperature gas streams during start-up, shut-down, and unplanned upsets or emergency events. The Rectisol® flare may be used for off-specification CO_2 during gasifier start-up or shut-down events. It is expected that a maximum of 40 hours per year of flaring for this purpose would be required by this flare.

During normal operations, the three flares will have pilot flames that will operate continuously. Emissions from the flares are generated from the continual operation of the natural-gas–fired pilots, and from periodic vent gases that are oxidized during planned start-ups and shut-downs of the Gasification Block. The annual emissions from each flare were estimated by adding the emissions from continual combustion of the pilot gas plus the planned use during gasifier start-up/shut-down events.

A summary of each flare emissions is presented in Table 3-6. Detailed emissions calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.8 Tail Gas Thermal Oxidizer

Associated with the operation of the sulfur recovery process, the Project will incorporate a thermal oxidizer on the TGTU. The thermal oxidizer will serve as a control device to oxidize any remaining H_2S (after scrubbing) and other vent gas that is generated during start-ups, shut-downs, and times of non-delivery of CO_2 product. In addition, miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) are directed to the thermal oxidizer during operation to prevent nuisance odors. The thermal oxidizer operates at high temperatures, and provides sufficient residence time to ensure essentially complete destruction of reduced sulfur compounds like H_2S to SO_2. The thermal

oxidizer fires natural gas continuously to reach and maintain the required operating temperature for proper thermal destruction. Pollutant emissions are generated from the firing of natural gas and the periodic oxidation of vent gas during SRU start-up. A summary of the tail-gas oxidizer emissions is presented in Table 3-6. Detailed emissions calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.9 Carbon Dioxide Vent

The CO_2 vent stack will allow for start-up and intermittent emergency venting of produced CO_2 when the CO_2 compression, transportation, or injection systems are unavailable. The CO_2 vent will enable the Project to operate, rather than be disabled, by brief periods when the CO_2 injection system is unavailable, and in doing so, prevents gasifier shut-down and subsequent gasifier restart with associated emissions.

A 260-foot stack height was chosen to satisfy HECA's inherently safe design practices to minimize ground-level CO_2 concentrations in the event of a CO_2 venting event under very low wind speeds. This stack height is within the calculated Good Engineering Practice (GEP) height.

The CO_2 vent exhaust stream will be nearly 100 percent CO_2, with small amounts of CO, VOCs, and H_2S. A summary of the maximum annual CO_2 vent stack emissions is presented in Table 3-6. Detailed emissions calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.10 Ammonia Synthesis Unit Start-Up Heater

The high-purity hydrogen stream from the PSA Unit, and nitrogen, from the ASU, are combined in an exothermic ammonia synthesis reaction that takes place at high temperature and high pressure across an iron-based catalyst. There is a large degree of heat integration within the Ammonia Synthesis Unit, and the substantial heat of reaction is recovered and used to generate steam. Cold liquid ammonia is stored in a tank at atmospheric pressure.

There are no routine operating emissions from the Ammonia Synthesis Unit. However, a start-up heater (natural-gas–fired) is used to heat the catalyst during a cold start of the unit. A 55-MMBtu/hr natural-gas–fired start-up heater is provided in the ammonia synthesis unit to raise the catalyst-bed temperatures during initial plant commissioning, or during start-up after a long period of plant shut-down. The annual heat input for this heater is not expected to exceed 7,700 MMBtu HHV, which is equivalent to approximately 140 hours of operation at full capacity.

The heater will use a low-NO_X burner to control exhaust emissions to no higher than 9 ppmvd at 3 percent O_2. CO emissions are based on 50 ppmvd at 3 percent O_2. PM_{10}, $PM_{2.5}$, and VOC emissions are based on vendor-supplied emission factors. SO_2 emissions are calculated based on 12.65 ppmv total sulfur in pipeline natural gas.

A summary of the Ammonia Synthesis Unit start-up heater emissions is presented in Table 3-6. Emissions and calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.11 Urea Absorbers

The purified and compressed CO_2 and the liquid ammonia are reacted in the Urea Unit to create a concentrated urea solution, which is pumped to the Urea Pastillation Unit. Lower-concentration urea solution is produced as a feedstock to the UAN Solution Plant. Vacuum evaporator/separator systems are used to produce the required urea solutions.

The off-gases from the urea synthesis process, consisting of inerts (CO_2, nitrogen, and water) present in the CO_2 feed, process air, and unreacted ammonia are cleaned before being vented in the HP scrubber, which operates at an elevated pressure. The off-gases are scrubbed first with process water, and second with clean, cold water. In this way, nearly all of the ammonia is scrubbed from the gas. Low pressure off-gases are cleaned in the low-pressure (LP) scrubber, which operates at close to atmospheric pressure. Here, the off-gas is scrubbed with clean, cold water to reduce the ammonia content in the vent.

The only emissions associated with the HP and LP Urea Absorbers are in the form of ammonia, which is reduced by the wet scrubber. Emissions from the HP and LP Urea Absorbers are presented in Section 5.3. Detailed emissions calculations are included in Appendix D, Operational Criteria Pollutant Emissions; and Appendix F, Toxic Air Contaminant Emissions.

3.4.2.12 Urea Pastillation Unit

The pastillation process is used to convert the urea melt into high-quality pastilles. This process unit is enclosed with a hood, and is exhausted through a baghouse, then vented. Limited ammonia and urea dust, which are classified as $PM_{10}/PM_{2.5}$, are emitted from this source. The HECA pastillation process $PM_{10}/PM_{2.5}$ emissions will be limited to a grain loading of no more than 0.001 grain per dry standard cubic foot (gr/dscf) by the baghouse. A summary of the Urea Pastillation Unit emissions is presented in Table 3-6. Detailed emissions calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.13 Nitric Acid Unit

Nitric acid production is a three-step process consisting of ammonia oxidation, NO oxidation, and absorption. Tail gas from the absorber column will be cleaned before being discharged by catalytic decomposition and reduction of both N_2O and NO_X.

The N_2O emissions are treated in a system classified as tertiary reduction, based on its location at the end of the tail gas heat recovery system. Primary and secondary reduction occurs in the nitric acid unit equipment without any catalysis, simply due to the high process temperature. In the tertiary reduction, a reducing catalyst that uses high temperature, rather than a reducing agent, converts 95 percent of the remaining N_2O emission to molecular nitrogen (N_2) and NO. The NO_X emissions (including the NO formed in the N_2O converter) are then reduced in one or more

SCR units, with injected ammonia as a reducing agent, as is typical for NO_X control in flue gas systems. Total NO_X emissions from this unit will not exceed 0.2 lb/ton of dry nitric acid, or 15 ppmvd NO_X. The HECA nitric acid plant will have an ammonia slip emission limit of 5 ppm downstream of the SCR.

A summary of the nitric acid unit emissions is presented in Table 3-6. Detailed emissions calculations are included in Appendix D, Operational Criteria Pollutant Emissions; and Appendix G, Operational Greenhouse Gas Emissions.

3.4.2.14 Ammonium Nitrate Unit

Ammonia and nitric acid are the feedstocks to the ammonium nitrate unit, which makes the ammonium nitrate solution. The ammonium nitrate unit vent stream contains water vapor and residual ammonium nitrate solution mist that is not removed by the demisting system. If this vent stream with mist is emitted directly to the atmosphere, the mist droplets would evaporate and result in PM emissions. These particulate emissions are substantially reduced by routing the vent stream to a water-scrubbing system before discharge to the atmosphere. This vent scrubber condenses the vapor into condensate, which then absorbs the previously entrained mist droplets. The condensate stream is either recycled to the neutralizer or mixed with cooling tower blowdown for treatment and disposal. The HECA Project will use a near-total condensing vent scrubbing system, and the scrubber vent particulate emissions will be less than 0.2 lb/hr. All PM emissions are assumed to be $PM_{2.5}$ or smaller.

A summary of the ammonium nitrate unit emissions is presented in Table 3-6. Detailed emissions calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.15 Material Handling Dust Collection

Particulate matter emissions are associated with the material handling of the feedstock, petcoke and coal, urea, and gasification solids. These operations include bulk material unloading, loading, belt conveying, belt transfer points, silo loading, and feedstock crusher, all controlled with a system of baghouses. Coal and petcoke will be stored in a storage building with separate coal and petcoke storage piles. The transfer conveyors are fully enclosed to control fugitive dust. Urea pastilles are stored in four buildings that are fully enclosed with roofing and siding. All PM emissions from these sources are assumed to be $PM_{2.5}$ or smaller.

A summary of the material-handling-system emissions is presented in Table 3-6. Detailed emissions calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.16 Fugitive Emissions

Fugitive emissions of VOC, CO, NH_3, H_2S, and trace HAPs and GHGs may occur in some areas of the facility due to leaks in the piping and components. Fugitive emissions are associated primarily with the Gasification Block and the Manufacturing Complex. An LDAR program will be implemented in select process areas to maximize emission reductions. LDAR is the primary established method for controlling fugitive emissions from various pieces of equipment, such as valves and seals.

Potential fugitive VOC emissions from piping components were estimated using the USEPA guidance, *Protocol for Equipment Leak Emission Estimates* (USEPA, 1995a). The emission factors used in the calculations are the Synthetic Organic Chemical Manufacturing Industry (SOCMI) factors from Table 7 of the referenced USEPA guidance document. An LDAR program will be implemented on select process areas with the largest estimated toxic air contaminant (TAC) and VOC fugitive emissions. Because the fugitive emission factors were based on factors for SOCMI facilities, the LDAR program implemented at this facility will meet the NESHAPs regulations, which are traditionally used at SOCMI facilities.

HECA LLC proposes to apply the LDAR program to the following areas in the Gasification Block, Area #1 (methanol), Area #5 (propylene), Area #7 (H_2S–laden methanol), Area #8 (CO_2-laden methanol), Area #9 (acid gas), and Area #10 (ammonia-laden gas), and all portions of the Manufacturing Complex. These areas were selected because they had the largest uncontrolled emission estimates for methanol, propylene, H_2S, and ammonia. The following compounds were included as VOCs (not all compounds are found in the gas in each process area): methanol, propylene, COS, and H_2S.

A summary of the fugitive emissions is presented in Table 3-6. Detailed emissions calculations are included in Appendix F, Toxic Air Contaminant Emissions, with additional details in Appendix D Operational Criteria Pollutant Emissions.

3.4.2.17 Emergency Generator Engines and Firewater Pump Engine

The Project will include two 2,922-horsepower standby diesel generators and one 556-horsepower standby firewater pump, located adjacent to the firewater tank. The diesel engines will exclusively combust ultra-low sulfur (15 ppm by weight or less) No. 2 diesel fuel.

The 2,922-horsepower diesel engines are installed in an outdoor enclosure and will be connected to the 480-volt (V) switchgear. The switchgear supplies essential service power to critical lube oil and cooling pumps, gasification and auxiliary steam systems, gasification quench system, station battery chargers, uninterruptible power supply, heat tracing, control room and emergency exit lighting, and other critical plant loads. Emissions were estimated based on hourly manufacturers' emission rates, as well as USEPA interim Tier 4 emissions standards for 2011 and newer-model equipment. Sulfur dioxide emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur. The annual emissions from these engines are based on a maximum non-emergency-use rate of 50 hours of operation per year each for the emergency generator engines, and 100 hours of operation per year for the fire pump engine. Emissions estimates for the three diesel engines are shown in Table 3-6. Emissions and calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

3.4.2.18 HECA Facility-Wide Criteria Pollutant Emissions

The total annual emissions of criteria pollutants from all stationary emission sources of the Project addressed in the previous subsections are shown in Table 3-6.

Table 3-6
Total Combined Annual Criteria Pollutant Emissions[1]

Pollutant / Equipment	NO_X	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$
	tons/yr					
HRSG/CTG	109.7	92.9	15.3	17.1	54.6	54.6
Coal Dryer	17.4	13.3	2.4	2.8	5.6	5.6
Auxiliary Boiler	1.4	8.6	0.9	0.5	1.2	1.2
Tail Gas Thermal Oxidizer	13.4	11.2	0.3	8.3	0.4	0.4
CO_2 Vent	N/A	124.1	2.8	N/A	N/A	N/A
Gasification Flare	3.2	18.5	0.01	0.02	0.03	0.03
Rectisol® Flare	1.2	0.8	0.01	0.3	0.03	0.03
SRU Flare	0.2	0.2	0.003	0.4	0.006	0.006
Cooling Towers[2]	N/A	N/A	N/A	N/A	25.5	15.3
Emergency Generators[3]	0.2	0.8	0.1	0.001	0.02	0.02
Fire Water Pump	0.09	0.2	0.01	0.0003	0.001	0.001
Nitric Acid Unit	17	N/A	N/A	N/A	N/A	N/A
Urea Pastillation Unit	N/A	N/A	N/A	N/A	0.2	0.2
Ammonium Nitrate Unit	N/A	N/A	N/A	N/A	0.8	0.8
Ammonia Start-Up Heater	0.04	0.1	0.02	0.01	0.02	0.02
Material Handling[4]	N/A	N/A	N/A	N/A	1.9	1.9
Fugitives	N/A	4.6	13.4	N/A	N/A	N/A
Total Annual	**163.7**	**275.2**	**35.4**	**29.4**	**90.3**	**80.2**

Source: HECA 2012
Notes:
1 Total annual emissions represent the maximum annual emissions during operations plus start-up and shut-down emissions
2 Includes contributions from all three cooling towers
3 Includes contributions from both emergency generators
4 Material handling emissions are shown as the contribution of all dust collection points.
HRSG = Heat Recovery Steam Generator
CTG = combustion turbine generator
CO = carbon monoxide
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOC = volatile organic compound

3.4.3 Commissioning

Construction is initially scheduled by plant area and major equipment erection requirements. Later, construction scheduling transitions to completion by system, in order to support turnover to the commissioning team.

The commissioning period of the Project is expected to be completed within 16 months, following mechanical completion (physical installation of all equipment). Commercial operation

will start when the commissioning and start-up activities are completed, and the licensor/ contractor guarantees and milestones have been achieved.

Commissioning is completed by system, with the utilities (fire protection, power, water, natural gas, steam, etc.) completed first. Commissioning the utility and support systems will require availability of electric power, water treating, natural gas, and cooling tower, as well as the safety systems that will be needed to support initial operations of the equipment. Commissioning the Diesel Firewater Pump and the Emergency Diesel Generators will produce air emissions during their initial operation and testing.

The major process units will be commissioned in a sequence that begins with the feed-producing units, and ends with the product-producing units and systems.

The major Gasification Block units consume electrical power. The Power Block also must be reliable before commissioning on hydrogen-rich fuel begins. For these reasons, the Power Block will be commissioned ahead of the Gasification Block. The commissioning for the Project will occur in four distinct phases, which are described in the following subsections.

3.4.3.1 Power Block Commissioning on Natural Gas

The Power Block will be initially commissioned on natural gas. The MHI 501 GAC® CT uses diffusion combustors with water injection, rather than dry, low-nitrogen oxide combustors. The following list briefly describes the steps for commissioning on natural gas:

- First fire
- Initial CT run-in
- Support of steam blows
- Initial steam turbine roll
- Nitrogen oxide tuning with steam injection
- Installation of SCR and oxidation catalyst
- CEMS drift test and source testing
- Power Block functional testing
- Water wash and Power Block performance testing and continuous operation test.

The emissions associated with the sequence above are shown in Table 3-7.

The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. An estimated 1,129 hours of operation during commissioning of the CTG/ HRSG on natural gas with partially abated emissions has been assumed for purposes of calculating cumulative commissioning emissions in Table 3-7. Fuel flow monitoring will be conducted for all tests.

HECA LLC will make every effort to minimize emissions of CO, VOCs, and NO_X during the commissioning period (SO_2 and PM commissioning emissions will be the same or less than during operations); however, not all of the equipment to abate these emissions will be fully operational at the start of the commissioning period.

Table 3-7
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
First fire	4	FSNL	Not operating	8.4	268.4	9,080	260	60
Rotor run-in	12	20%	Not operating	25.2	805	27,240	780	180
Steam blows	168	40%	Not operating	520.8	15,657	152,544	1,966	2,520
Restoration	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Initial steam turbine roll	24	40%	Not operating	74.4	2,237	21,792	281	360
NO_X tuning with water injection and initial STG loading	16	40%	Not operating	49.6	174	6057.6	112	240
NO_X tuning with water injection and initial STG loading	16	80%	Not operating	76.8	6,259	5,512	60.8	240
Finalize NO_X control constants	40	40%	Not operating	124	436	15,144	280	600
Finalize NO_X control constants	40	60%	Not operating	160	11,922	14,460	243.2	600
Finalize NO_X control constants	96	80%	Not operating	460.8	37,555	33,072	364.8	1,440
GTG water wash and contractual emission and simple cycle performance testing	16	80%	Not operating	76.8	6,259	5,512	60.8	240
Install SCR and oxidation catalyst	24	80%	Testing	112.8	818	624	142	360
CEMS drift and source testing	64	80%	Operating	300.8	2,182	1,664	377.6	960
Functional testing demonstration hours (six starts)	315	20% to 40%	Operating	859.95	24,466	48,857	1965.6	4,438
Functional testing demonstration hours (six shut-downs)	54	20% to 40%	Operating	139.32	4830.84	50,898	1180.98	810
Functional testing steady state hours	48	80%	Operating	225.6	1,637	1248	283.2	720

Table 3-7
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas (Continued)

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
GTG water wash and preparation for performance testing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Continuous operation test	192	80%	Operating	902.4	6,547	4992	1132.8	2880
	1,129	**Total (lb)**		**4,118**	**122,055**	**398,696**	**9,490**	**16,648**
		Total (ton)		**2.1**	**61.0**	**199.3**	**4.7**	**8.3**

Source: HECA 2012.

Notes:
CEMS = continuous emissions monitoring system
CO = carbon monoxide
CTG = combustion turbine generator
HRSG = heat-recovery steam generator
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOCs = volatile organic compounds

Once it has been installed, the oxidation catalyst will abate CO and VOC emissions from the gas turbine and the duct burners because it is essentially a passive device. Although the SCR catalyst is in some cases able to be installed prior to initial start-up of the combustion turbine, it may not be installed until later in the commissioning period, after completion of steam blows, which could deposit debris and otherwise damage the catalyst. The SCR catalyst may not be installed at the same time as the oxidation catalyst. Emissions of NO_X from the gas turbine and the duct burners may be only partially abated during times that the gas-turbine burners are being tuned and the SCR system is being tested.

Commissioning emissions were very conservatively estimated based on the worst-case assumption that the control efficiency of the applicable abatement systems is essentially zero during significant portions of the commissioning phase. The CEMS will also be undergoing commissioning at this time. Once the CEMS is commissioned, it will record emissions of NO_X and CO. Emissions of SO_2 and PM_{10} may be quantified by using emission factors based on fuel flow.

3.4.3.2 Gasification Block and Balance of Plant Commissioning

The following description includes the commissioning activities that are expected to have air emissions in plant areas other than the Power Block and Manufacturing Complex. The sequence of activities summarized here assumes that the major utility support systems are already operational (power distribution, firewater, power plant and instrument air, water treatment, steam, boiler feedwater, etc.). The key activities and events are listed below:

- Testing diesel generators
- Testing diesel firewater pump
- Auxiliary boiler initial firing and burner tuning
- Auxiliary boiler source testing
- Auxiliary boiler operation to support gasification commissioning (typically when the Power Block is not operating)
- Operation of the Power Block in support of Gasification Block commissioning
- Cooling tower operation supporting the ASU, Combined Cycle Power Block, and Gasification Block (process cooling tower)
- Gasification flare testing and operation in support of Gasification Block commissioning
- Rectisol® flare testing and operation in support of AGR Unit commissioning
- SRU Flare testing and operation in support of Gasification Block commissioning
- Gasifier testing and operation
- Testing and operation of the AGR, SRU, and Tail Gas Compression Unit
- Testing the SRU thermal oxidation
- Venting CO_2 to support the testing and operation of the AGR and CO_2 compression system.

The emissions associated with the sequence above are shown in Table 3-8.

The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. Fuel-flow monitoring will be conducted during all equipment tests.

Table 3-8
Duration and Criteria Pollutant Emissions for Commissioning of the Gasifier and Balance of Plant

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
Test Firewater Diesel Pump	6	100%	Operating	0	11	19	0	1
Test Diesel Generators (total both units)	20	100%	Operating	1	62	36	3	14
Auxiliary Boiler burner and FGR tuning	96	25% to 100%	Tuning	26	460	945	102	64
Auxiliary Boiler source testing	64	100%	Operating	28	78	483	52	65
Auxiliary Boiler operation to support commissioning	672	100%	Operating	292	823	5,072	548	685
ASU Cooling Tower	7,000	100% 2000 TDS	Operating	0	0	0	0	1,570
Process Cooling Tower	7,000	50% 4500 TDS	Operating	0	0	0	0	12,950
Power Block Cooling Tower	7,000	50% 4500 TDS	Operating	0	0	0	0	7,520
Functional testing flares on natural gas	72	Reduced	Operating	29	1,728	1,152	19	43
Flare operation on un-shifted syngas	168	50%	Operating	685	23,520	672,000	0	0
Flare operation on shifted (high-H_2) syngas	504	50%	Operating	2,056	70,560	372,960	0	0
Thermal oxidizer—SRU refractory cure and heating	576	Minimum	Operating	6	317	259	20	23
Thermal oxidizer to support commissioning	711	Min to 100%	Operating	7,844	1,669	1,408	68	68
Start-up/standby coal drying vent ops (CTG on natural gas)	120	40% to 80%	Operating	36	544	5,306	228	108

Table 3-8
Duration and Criteria Pollutant Emissions for Commissioning of the Gasifier and Balance of Plant (Continued)

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
Normal coal drying vent ops (CTG on H_2-rich fuel)	1,200	100%	Operating	1,080	5,280	3,840	720	1,680
CO_2 vent	672	50%	Operating	0	0	165,312	3,696	0
		Total (lb)		**12,084**	**105,051**	**1,228,793**	**5,457**	**24,792**
		Total (ton)		**6.0**	**52.5**	**614.4**	**2.7**	**12.4**

Source: HECA 2012.

Notes:
CEMS = continuous emissions monitoring system
CO = carbon monoxide
CO_2 = carbon dioxide
CTG = combustion turbine generator
H_2 = hydrogen
HRSG = heat-recovery steam generator
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
TDS = total dissolved solids
VOCs = volatile organic compounds

3.4.3.3 Power Block Commissioning on Hydrogen-Rich Fuel

The Power Block will require additional testing and NO_X emissions tuning with hydrogen-rich fuel. The testing will cover the allowable load ranges. As described previously, the Power Block will be commissioned first on natural gas. The oxidation catalysts are assumed to be in service and active when the HRSG operating temperature is achieved. The SCR catalyst and ammonia injection system are assumed to be operating whenever the SCR catalyst temperature is within the required range, and operation is sufficiently stable. Ammonia injection may be off-line during the initial phases of NO_X emissions tuning. The key activities and events that are expected to produce air emissions are listed below:

- Start-up, shut-down, and standby operation of MHI 501 GAC® on natural gas
- CT nitrogen oxide tuning on 100 percent hydrogen-rich fuel
- CT nitrogen oxide tuning on part load
- Water wash and performance testing on hydrogen-rich fuel
- Duct-burner testing on hydrogen-rich fuel
- Duct-burner testing on PSA off-gas (if available)
- Source testing on hydrogen-rich fuel across the load range
- Functional testing including fuel transfers and load changes
- IGCC performance test
- IGCC operational reliability test.

The emissions associated with the sequence above are shown in Table 3-9. The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. An estimated 1,182 hours of operation during commissioning of the CTG/HRSG on hydrogen-rich fuel with partially abated emissions has been assumed in calculating cumulative commissioning emissions in Table 3-9. Fuel-flow monitoring will be conducted for all tests.

3.4.3.4 Manufacturing Complex Commissioning

The Manufacturing Complex is comprised of several interrelated plants and support systems. High-purity hydrogen and high-purity nitrogen are feedstocks to the Ammonia Synthesis Unit, which produces anhydrous ammonia. Anhydrous ammonia and high-purity CO_2 are feedstocks to the Urea Unit. The Urea Unit produces approximately 99 weight percent urea solution that feeds the Urea Pastillation Unit, as well as 80 weight percent urea solution that feeds the UAN Unit. Anhydrous ammonia is the feedstock for the Nitric Acid Unit and the Ammonium Nitrate Unit. The 80 weight percent urea solution and ammonium nitrate solution are feedstocks to the UAN Unit. The key Manufacturing Complex commissioning activities and events that are expected to produce air emissions through the use of fired heaters or flare systems are listed below:

- PSA Units 1 and 2 including PSA off-gas compression (brief flaring of hydrogen and PSA off-gas)
- High-purity hydrogen compression and nitrogen compression (brief flaring of hydrogen)
- Test HRSG PSA off-gas duct burner system (if not already completed)

Table 3-9
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen-Rich Fuel

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
GTG starts on natural gas (for 20 starts)	50	20% to 40%	Not operating	116	4,952	64,460	1,184	676
GTG hold time allowance (40% load on H_2-rich fuel)	240	40%	Operating	576	4,795	5,832	1,104	3,120
GTG shut-down hold at 40% load on H_2-rich fuel (for 20 shut-downs)	80	40%	Operating	192	1,598	1,944	368	1,040
GTG fired shut-downs on natural gas (for 20 shut-downs)	100	20% to 40%	Operating	248	7,368	162,260	3,512	1,500
GTG/HRSG standby operation on natural gas	120	40%	Partially Operating	324	1,171	10,004	444	1,800
Gasifier fuel turnover tuning @ 40% H_2-rich fuel	20	40%	Partially Operating	48	1,332	1,620	92	300
CTG NO_X tuning on H_2-rich fuel	16	40%	Partially Operating	38	1,066	1,296	74	240
Gasifier feedstock dryer tuning	24	40%	Partially Operating	58	1,598	1,944	110	360
STG gasifier/SGC steam operation tuning	20	40%	Partially Operating	48	1,332	1,620	92	300
Zero flare tuning	48	40%	Operating	115	3,197	3,888	221	720
CTG NO_X tuning on H_2 rich-fuel	60	75%	Operating	246	1,308	960	186	900
CTG NO_X tuning on H_2 rich-fuel	60	100%	Operating	246	1,500	1,098	210	900
CTG load change testing	60	40% to 100%	Operating	198	2,748	2,982	246	900
CTG trip test	36	40% to 100%	Operating	119	1,649	1,789	148	540

Table 3-9
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen-Rich Fuel (Continued)

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
GTG water wash and contractual emission and simple cycle performance testing on H_2-rich fuel	24	100%	Operating	72	689	226	89	360
Duct burner testing on H_2-rich syngas	48	100%	Operating	192	1,397	744	187	720
Duct burner testing on PSA off-gas	48	60%	Operating	240	893	653	125	720
Source testing @ 100% H_2-rich syngas (duct fired, H_2-rich + PSA)	16	100%	Operating	80	470	344	66	240
Source testing @ 70% H_2-rich syngas (duct fired, PSA only)	16	70%	Operating	64	298	218	42	240
IGCC performance and operating test	96	70% to 100%	Operating	432	2,304	1,690	326	1,440
	1,182	**Total (lb)**		**3,652**	**41,665**	**265,571**	**8,825**	**17,016**
		Total (ton)		**1.8**	**20.8**	**132.8**	**4.4**	**8.5**

Source: HECA 2012.

Notes:
CEMS = continuous emissions monitoring system
CO = carbon monoxide
CTG = combustion turbine generator
HRSG = heat-recovery steam generator
H_2 = hydrogen
lb = pound
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOC = volatile organic compound

- Test Ammonia Synthesis Unit (use of start-up heater, brief flaring during catalyst reduction, and recycle compressor testing)
- Build ammonia storage inventory
- CO_2 purification and purified CO_2 compression (brief venting of CO_2)
- Test Urea Unit (HP loop passivation and heating)
- Test Urea Pastillation Unit (functional testing including particulate control systems)
- Test Nitric Acid Unit (tail gas nitrous oxide abator)
- Test Ammonium Nitrate Unit (ammonium nitrate vent scrubber)
- Test UAN Unit (neutralizer overhead cleanup scrubber)
- Manufacturing Complex performance testing
- IGCC and Manufacturing Complex functional dispatch testing
- Plant-wide performance test
- Plant-wide reliability demonstration.

The emissions associated with the sequence above are shown in Table 3-10. The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. An estimated 3,388 hours of operation during commissioning from the combination of all Manufacturing Complex sources has been assumed for purposes of calculating cumulative commissioning emissions in Table 3-10.

3.4.4 Mobile Sources

On-site truck and train trip emissions were incorporated in the dispersion modeling for CEQA purposes. Mobile sources were not included in the PSD SIL or National Ambient Air Quality Standards (NAAQS) analyses. Trucks and trains delivering feedstock fuels and removing products would travel to the Project Site on a regular basis. The maximum expected numbers of truck and train trips for the averaging period corresponding to the ambient air quality standards are summarized in Table 3-11. This section describes the on-site emissions associated with coke deliveries by trucks and coal deliveries by rail, as well as transportation of HECA-generated products by means of both trucks and rail.

The petcoke trucks would enter the plant from Station Road, at Tupman Road, and then proceed south to the truck-unloading station. At the truck-unloading area, each truck would idle for no more than 5 minutes while unloading, then loop back through the truck scales and wash rack to exit the plant onto Station Road. The product trucks and trains are loaded in the product-loading area in the center of the Project site. The product trucks would also enter and exit the plant from Station Road at Tupman Road and pass through the truck scales and wash rack.

Coal will be transported to the site by train, and some of the product will be transported off-site via train. The trains would enter and exit the northwestern corner of the site near Dairy Road and Adohr Road. The train feedstock unloading and product loading stations are in the center of the Project Site. In addition to the feedstock and product trains, there will be one dedicated switching engine on-site to move either the feedstock or product rail cars.

Table 3-10
Duration and Criteria Pollutant Emissions for Commissioning of the Manufacturing Complex

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
High-purity H_2 compressor testing to flare	48	100%	Operating	0.0	3,897.6	0.0	0.0	0.0
Operation of ammonia unit start-up heater	240	25% to 100%	Operating	20.1	108.2	364.1	39.4	49.2
Ammonia plant flaring during catalyst reduction	60	Minimum	Operating	0.0	210.0	0.0	0.0	0.0
Particulate emissions from urea pastillation	800	100%	Operating	0.0	0.0	0.0	0.0	40.0
Nitric acid plant tail gas NO_X abator tuning	60	25% to 100%	Tuning	0.0	1,260.0	0.0	0.0	0.0
Nitric acid plant tail gas with NO_X abator	600	100%	Operating	0.0	2,520.0	0.0	0.0	0.0
Ammonium nitrate vent scrubber emissions	660	100%	Operating	0.0	0.0	0.0	0.0	132.0
Urea storage and handling	800	100%	Operating	0.0	0.0	0.0	0.0	256.0
Venting high purity CO_2 for urea unit commissioning	120	25% to 100%	Operating	0.0	0.0	3.5	11.9	0.0
	3,388	**Total (lb)**		**20.1**	**7,995.8**	**367.5**	**51.3**	**477.2**
		Total (ton)		**0.01**	**4.00**	**0.18**	**0.03**	**0.24**

Source: HECA 2012.
Notes:
CEMS = continuous emissions monitoring system
CO = carbon monoxide
CO_2 = carbon dioxide
CTG = combustion turbine generator
HRSG = heat-recovery steam generator
H_2 = hydrogen
Lb = pound
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOCs = volatile organic compounds

Table 3-11
On-Site Maximum Trucks and Trains by Averaging Period

Period	Petcoke Trucks	Product Trucks	Miscellaneous Trucks	Coal Trains	Product Trains
1 hour	6	13	5	1	1
3 hours	17	39	5	1	1
8 hours	44	104	5	2	1
24 hours	55	130	5	2	1
Annual	15,200	20,880	1,818	109	153

Source: HECA, 2012.

Notes: The facility will also maintain 20 vehicles (10 gasoline and 10 diesel trucks) for onsite operations and maintenance (O&M).

Emissions associated with on-site truck movements were calculated using heavy-heavy duty diesel truck emission factors for all trucks, except the Operations and Maintenance trucks, which were calculated by means of the light-heavy-duty gasoline and diesel factors, from the California Air Resources Board (CARB) on-road emissions model EMFAC2007. The 2007 version of EMFAC was used to calculate all on-road vehicle emissions, because this version of the model has been approved by USEPA for use in projects that require USEPA review, such as the NEPA analysis and federal conformity determination that will be conducted for HECA.

Emission factors from EMFAC2007 are provided in terms of grams per mile, which were converted to grams per second for input to the dispersion model, based on the distance traveled and the number and frequency of truck trips. EMFAC2007 factors vary depending on the calendar year for which the model is run, because the emission factors reflect adopted CARB engine and fuel standards, and are also based on the vehicle fleet age and composition. The vehicle fleet used by EMFAC2007 is based on an analysis of California Department of Motor Vehicles (DMV) registration data, which vary by calendar year and geographic area. Thus, EMFAC2007 runs for earlier calendar years will produce higher emission factors because of older, higher-polluting vehicles still in the vehicle fleet.

The anticipated Project commercial operation date is 2017. HECA LLC will use a fleet of delivery trucks that are model year 2010 or newer; thus EMFAC2007 emissions factors model year 2010 vehicles were used in the emission calculations.

The emissions factors for criteria pollutants for line-haul and switch locomotives were obtained from the USEPA document "Technical Highlights: Emission Factors for Locomotives" for Tier 3 engines (USEPA, 2009a). On-site feedstock and product train emissions were calculated assuming that the line-haul engines will operate in Notch 1 or idling for the majority of their time within the site boundaries; therefore, emissions were conservatively estimated for Notch 1 horsepower. The percentage of total engine horsepower used at Notch 1 was obtained from the "Port of Long Beach Air Emissions Inventory for 2007," which was based on data derived from USEPA (Port of Long Beach, 2009). Emissions from the on-site switching engine were based on USEPA Tier 3 emission factors and maximum switching engine horsepower of 260 horsepower.

The on-site Project-related mobile emissions are summarized in Table 3-12. On-site transportation emissions and calculations are included in Appendix D, Operational Criteria Pollutant Emissions.

Table 3-12
Operational Transportation Emissions Related to the Project

Emission Source	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
	Annual Emission Rates (tons/year)					
On-site train	1.09	2.65	0.05	0.05	0.06	0.28
On-site truck	0.63	0.99	0.15	0.05	0.01	0.16
Total Emission (ton/ year)	**1.72**	**3.64**	**0.20**	**0.10**	**0.07**	**0.44**

Source: HECA, 2012.

Notes:

On-site worker travel and associated emissions are negligible

3.5 GREENHOUSE GAS EMISSIONS

The GHG emissions presented in this section reflect the design of the HECA facility to accomplish the following key Project objectives:

- to provide dependable, low-carbon baseload electricity;
- to help meet future electrical power needs and to support a reliable power grid that is an essential component to meeting California's GHG reduction goals for 2020 and beyond; and
- to mitigate impacts related to climate change by dramatically reducing GHG emissions relative to those emitted from conventional power generation and nitrogen-based product manufacturing by capturing and sequestering CO_2 emissions.

GHG emissions from HECA sources are minimized through implementation of GHG BACT as described in Section 3.3 and Appendix C, Greenhouse Gas BACT Analysis. Annual GHG emissions were estimated for three operating scenarios, as described below:

- Early operations, which are expected to last approximately 2 years, during which time hydrogen-rich fuel availability will be approximately 65 to 75 percent. During this period, all sources are expected to be operated at maximum operating conditions, including two plant start-ups and shut-downs. The CO_2 vent is included with maximum permitted venting emissions of up to 504 hours at full capacity.
- Mature operations, which are expected to occur after the first 2 years of commercial operation, when the hydrogen-rich fuel availability will be approximately 85 percent. At this stage, significantly less venting is expected to occur; thus, CO_2 vent emissions are estimated based on approximately 10 days of venting at 50 percent capacity (or 120 hours of venting at 100 percent capacity). All other sources are operated at maximum operating conditions, including two plant start-ups and shut-downs.
- Steady-state operations, which occur in the same time frame as mature operations; that is, after the 2 years of early operation. In this scenario, emissions are estimated based on

maximum operating conditions for all sources for a year, including two start-ups and shut-downs, but no CO_2 venting. Emissions from operation of the CTG/HRSG on syngas are included; no natural gas use is included, except during the start-up and shut-down events.

The CO_2 vent stack will allow for start-up and intermittent emergency venting of produced CO_2 when the CO_2 compression, transportation, or injection systems are unavailable. The CO_2 vent exhaust stream will be nearly pure CO_2; thus, total exhaust flow was used to estimate the CO_2 venting emissions.

Venting durations during early and mature operations were determined based on the following types of events that could occur over any 1-year period: (A) Gasification Block cold start-ups; (B) unplanned outages of the CO_2 compressor; (C) unplanned outages of the CO_2 pipeline; and (D) CO_2 Off-Taker unable to accept. The scenarios shown in Table 3-13 were developed to provide a conservative estimate of the venting emissions that may be required during the early operations, and for mature operations. Safe operation of the HECA Project is a key factor in considering whether to shut down the gasifier during short, unplanned CO_2 transportation system events. Shutting down the entire Gasification Block and restarting it increases the risk of upsets, and must be considered when evaluating whether to vent CO_2 or shut down the Gasification Block.

Table 3-13
Carbon Dioxide Venting Scenarios

Scenario for Early Operation				
	Event	**Events (per yr)**	**Duration or Time to Repair (days per event)**	**Duration of CO_2 Vent Operation (days/year)[1]**
A	Cold Gasification Block start-up	2	3	6
B	CO_2 Compressor unplanned outage	4	2	8
C	CO_2 Pipeline unplanned outage	1	1	1
D	CO_2 off-taker unable to accept	2	3	6
Total Days				21
Scenario for Mature Operation				
	Event	**Events (per yr)**	**Duration or Time to Repair (days per event)**	**Duration of CO_2 Vent Operation (days/year)[1]**
A	Cold Gasification Block start-up	1	1	1
B	CO_2 Compressor unplanned outage	2 to 4	2	4 to 8
C	CO_2 Pipeline unplanned outage	0 to 1	1	0 to 1
D	CO_2 off-taker unable to accept	0	0	0
Total Days				5 to 10

Source: HECA, 2012.

Note:

[1] The flow rate of CO_2 during venting will vary depending on the operations at the Manufacturing Complex and Power Block. Venting is expected to occur at 50 to 85 percent of the maximum designed CO_2 venting rate.

The GHG emissions from the CTG/HRSG and coal dryer were estimated based on the composition of the hydrogen-rich fuel and PSA off-gas, the volume of each gas stream to be used annually, and a methane destruction rate of 98 percent in the CT combustion.

Emissions of CO_2, CH_4, and N_2O from combustion of natural gas in the CTG/HRSG, auxiliary boiler, gasification flare, SRU flare, Rectisol® flare pilot, thermal oxidizer, and ammonia synthesis start-up heater were estimated using emission factors from the California Climate Action Registry (CCAR) General Reporting Protocol Version 3.1 (January 2009). To calculate the N_2O emissions from the CTG/HRSG and coal dryer during combustion of hydrogen-rich fuel and PSA off-gas, the CCAR natural gas emission factor was used, even though actual emissions are expected to be lower than from the combustion of natural gas.

During a gasifier start-up or shut-down event, the Rectisol® unit may not be fully operational; thus, this gas stream may need to be flared. Upstream of the Rectisol® unit, the gas is relatively high in CO_2; thus, the GHG emissions were based on the gas stream composition.

Fugitive emissions of CO_2 may occur in some areas of the facility due to leaks in the piping and components. These emissions will be minimized through implementation of an LDAR program. Detailed emissions calculations are presented Appendix F, Toxic Air Contaminant Emissions.

CO_2 is used in the process of making urea and will be emitted from the urea absorber vents. Emission calculations are based on data provided by Project design engineers.

Nitric acid production is a three-step process consisting of ammonia oxidation, NO oxidation, and absorption. Tail gas from the absorber column will be cleaned before being discharged by catalytic decomposition and reduction of both N_2O and NO_X. The N_2O emissions are treated in a tertiary reduction system, based on its location at the end of the tail gas heat recovery system. Primary and secondary reduction occurs in the nitric acid unit equipment without any catalysis simply by the high process temperature. In the tertiary reduction, a reducing catalyst that uses high temperature rather than a reducing agent converts 95 percent of the remaining N_2O emission to N_2 and NO. The only GHG emission associated with the nitric acid unit is N_2O. Emissions were estimated based on nitric acid production a vendor supplied emission factor and the destruction efficiency.

The circuit breakers will also have the potential to emit a very small amount of GHG, sulfur hexafluoride (SF_6). Circuit breakers do not emit SF_6 directly, but they do have the potential for fugitive emissions (leaks). The circuit breakers will be designed to have a leakage rate of at most 0.5 percent annually. Emissions are based on the amount of SF_6 in each circuit breaker and the leakage rate.

Emergency generators and firewater pump engines emissions of CO_2, CH_4, and N_2O were estimated using diesel emission factors from of the CCAR General Reporting Protocol Version 3.1 (January 2009).

Table 3-14 presents the annual CO_2e emissions from all stationary sources at HECA in metric tons (tonnes) during the early operations phase. This operational phase represents the maximum total Project annual CO_2e emissions. Detail emission calculations can be found in Appendix G, Operational Greenhouse Gas Emissions.

Table 3-14
Maximum Annual CO_2e Emissions - Early Operations

Source	Permitted CO_2e Emissions (tonne/yr)
CTG/HRSG H_2-rich fuel and PSA off-gas	269,153
CTG/HRSG natural gas	44,772
CO_2 Vent	174,113
SF_6 circuit breakers	86
Flares	8,257
Thermal oxidizer	5,946
Emergency generators and fire pump	181
Auxiliary boiler	24,782
Ammonia synthesis plant start-up heater	409
Urea absorber vents	116
Nitric acid unit	7,426
Fugitives	35
Total CO_2e Annual Emissions	**535,278**

Source: HECA, 2012.
Notes:
Maximum permitted emissions include periods of start-up and shut-down.
CO_2e = carbon dioxide equivalent
CO_2 = carbon dioxide
CTG = combustion turbine generator/heat recovery steam generator
H_2 = hydrogen
SF_6 = sulfur hexafluoride

For comparison to the California SB 1368 Greenhouse Gases Emission Performance Standard of 1,100 lb CO_2/MWh, CO_2 emissions and electricity production were calculated following CEC's "Regulations Establishing and Implementing a Greenhouse Gases Emission Performance Standard for Local Publicly Owned Electric Utilities" (CEC, 2012).

The SB 1368 emission calculations include only the annual CO_2 emissions from each fuel used in any component directly involved in electricity production, or associated with the sequestration of CO_2. Emissions from electricity production come from the CTG/HRSG when burning syngas, PSA off-gas, and natural gas; and subsequently, the coal dryer. Emissions associated with the CO_2 sequestration include the CO_2 vent and fugitives from CO_2 preparation for sequestration. HECA will provide OEHI with sequestration-ready CO_2; that is, no additional compression or processing would be needed to sequester the CO_2 after it leaves the HECA site. The SB 1368 emission calculations do not include SF_6 from the circuit breakers or emissions associated with the Gasification Block (flares, thermal oxidizer), Manufacturing Complex (ammonia synthesis plant start-up heater, urea absorbers, and nitric acid unit), or emissions from the auxiliary boiler, emergency generators, fire pump, and vehicles.

The net electricity production calculated for SB 1368 compliance for hydrogen-rich fuel generation includes the net power exported plus the power used on-site in the Manufacturing Complex, minus the steam generated from the ammonia production unit. The net power exported (267 MW) is presented in Table 2-11. Approximately 58 MW of power will be used in the Manufacturing Complex, and about 5 MW of steam generated in the ammonia production unit will be added to the HRSG. Thus, the net electricity production for SB 1368 for hydrogen-rich fuel generation is 320 MW. The net electricity production for natural-gas generation is 300 MW (presented in Table 2-11).

Table 3-15 compares the CO_2 emissions of the Project with the SB 1368 emission standard for the three scenarios defined previously. CO_2 emissions from the electricity production at HECA are approximately 225 lb/MWh during steady-state operations on hydrogen-rich fuel. The maximum CO_2 emissions during early operations, including emissions from natural-gas operation, start-up, shut-down, and CO_2 venting, would be approximately 400 lb/MWh.

Table 3-15
Annual CO_2 Emissions for SB 1368 Emission Performance Standard

Operating Parameters	Early Operations (Maximum Permitted)	Mature Operations	Steady-State Syngas Operations
Natural gas operation, hours per year	351	351	15
Hydrogen-rich fuel operation, hours per year	8,108	8,108	8,108
Intermittent CO_2 venting, hours per year	504	120	0
Electricity generated, MWh	2,699,860	2,699,860	2,599,060
Source	**CO_2 Emissions (metric ton/yr)**		
CTG/HRSG hydrogen-rich fuel and PSA off-gas	258,856	258,856	258,856
CTG/HRSG natural gas	44,729	44,729	1,911
CO_2 vent	174,113	41,456	0
Fugitives	31	31	31
Total CO_2 Annual Emissions	**477,729**	**345,071**	**260,799**
CO_2 lb/MWh	390.0	281.7	221.2

Source: HECA, 2012.
Notes:
- Early operations emissions include two periods of start-up and shut-down, natural gas use in the CTG, and 504 hours of CO_2 venting.
- Mature operations emissions include two periods of start-up and shut-down, natural gas use in the CTG and 120 hours of CO_2 venting.
- During steady-state operation, the CTG and duct burners will fire only hydrogen-rich fuel and PSA off-gas; it includes two start-ups and shut-down (which includes natural gas), but no natural gas backup use and no CO_2 venting.
- The fugitive CO_2 emissions are from all process areas; therefore, overestimate the emissions from the sequestration process.

The maximum emissions are less than one-half of those from a typical natural-gas combined-cycle power plant. In summary, the Project's GHG emissions will be well below the 1,100 lb CO_2/MWh threshold requirement of SB 1368, and the NSPS of 1,000 lb CO_2/MWh threshold proposed by USEPA.

GHG emissions calculations associated with the operation of HECA are included in Appendix G, Operational Greenhouse Gas Emissions.

3.5.1 Operational Greenhouse Gas Emissions—Mobile Sources

This section describes the emissions from the transportation associated with feedstock transportation and product export. On-site vehicle GHG emissions are based on the same data as the criteria pollutants emissions described earlier. The emission factors for CO_2 from EMFAC2007 were used for the on-road vehicles. The emission factors for N_2O and CH_4 are based on Table C.4 in the CCAR General Reporting Protocol Version 3.1 (January 2009) for diesel- and gasoline-fueled trucks.

The CO_2 emission factors for switching and line-haul locomotives for Tier 3 emissions were used (40 CFR Part 1033, USEPA Switch and Line-haul Locomotive Emission Standards). CH_4 and N_2O factors from CCAR General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) were used for locomotives.

On-site transportation GHG emissions are presented in Table 3-16, and calculation details are included in Appendix G, Operational Greenhouse Gas Emissions.

Table 3-16
Greenhouse Gas Emissions Associated with the On-site Mobile Sources During Project Operations

Source	Annual CO_2e Emissions (tonne/yr)
On-site trucks	413
On-site trains	291
Total CO_2e Annual Emissions	**704**

Source: HECA, 2012.

Notes:

On-site worker travel and associated emissions are negligible.

4.1 DISPERSION MODELING METHODOLOGY

The purpose of the air quality impact analyses is to evaluate whether or not criteria pollutant emissions resulting from the Project will cause or contribute significantly to a violation of a California or National AAQS. Mathematical models, designed to simulate the atmospheric transport and dispersion of airborne pollutants, are used to quantify the maximum expected impacts of Project emissions for comparison with applicable regulatory criteria. Potential impacts of TAC emissions from the Project are evaluated in Section 5, Health Risk Assessment.

The impacts from HECA operations will be associated with the operation of the Gasification Block, Power Block, Manufacturing Complex, material handling, and ancillary equipment; and for CEQA, mobile sources were included and compared against the California Ambient Air Quality Standards (CAAQS). Impacts from commissioning the Project are also analyzed.

The air quality modeling methodology described in this section has been documented in formal modeling protocols, which have been submitted for comment to CEC, SJVAPCD, and USEPA Region IX. The modeling protocols formally submitted and docketed are as follows:

- Air Quality Modeling Protocol for the HECA Power Project, Kern County, California, February, 2009 (URS, 2009a).
- Modeling Protocol for Parameter Selection Specific to the 1-hour NO_2 NAAQS Regional Modeling for the HECA Project, January 20, 2011 (URS, 2011).
- Modeling Protocol Supplement for the HECA Project (URS, 2012).

The modeling approaches used to assess various aspects of the Project's potential impacts to air quality are discussed below, and follow the methodologies outlined in the modeling protocols. Electronic modeling input and output files will be submitted with this application.

4.1.1 Model and Model Option Selections

The impacts of Project operations on criteria pollutant concentrations in receptor areas within approximately 6 miles (10 kilometers) from the Project Site and Controlled Area were evaluated using the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD [Version 12060]). AERMOD is appropriate for this AFC Amendment because it has the ability to assess dispersion of emission plumes from multiple point, area, or volume sources in flat, simple, and complex terrain, and to use sequential hourly meteorological input data. The regulatory default options were used, including building and stack tip downwash, default wind speed profiles, exclusion of deposition and gravitational settling, consideration of buoyant plume rise, and complex terrain.

Source groups will be used to aid in identifying impacts from individual permit units and to obtain the total modeled impacts from all sources, stationary and mobile (ALLWMOB), and all sources minus vehicles (ALLNOMOB). This way one model run can be conducted for pollutants with both a NAAQS and CAAQS for a given averaging.

Compliance with SJVAPCD Rule 2201 modeling requirements for attainment pollutants is demonstrated by modeling the maximum ground level concentrations of the Project at any receptor and adding conservative background concentrations, based on recent data from the most representative air quality monitoring stations. The Project will not be considered to cause or contribute to a near-field ambient air quality violation unless impacts from these sources combined with the background concentration exceed the most stringent AAQS.

Note that emissions reduction credits will be obtained by HECA LLC to offset Project emissions increases of the following pollutants: NO_X, VOC, PM_{10}, and SO_2, as HECA emissions of these pollutants are above the SJVAPCD emission offset triggering levels specified in the District's Rule 2201. No credit was taken for emission offsets in the modeling analysis.

Evaluation of commissioning and operational NO_2 concentrations (1-hour and annual averaging times) was accomplished using the ozone limiting method Plume Volume Molar Ratio Method (PVMRM) option in AERMOD. The PVMRM option accounts for the role of ambient O_3 in limiting the conversion of emitted NO_X—which occurs mostly in the form of nitrogen oxide (NO)—to NO_2, the pollutant regulated by ambient standards. The input data needed to execute the AERMOD-PVMRM model were provided by SJVAPCD, including representative hourly O_3 monitoring data for the same years corresponding to the meteorological input record.

To evaluate whether urban or rural dispersion parameters should be used in model simulations, an analysis of land use adjacent to the Project Site was conducted in accordance with Section 8.2.8 of the *Guidelines on Air Quality Models* (USEPA, 2003), and Auer (1978), USEPA AERMOD implementation guide (USEPA, 2004), and its addendum (USEPA, 2006). Based on the Auer land use procedure, more than 50 percent of the area within an approximately 2-mile (3-kilometer) radius of the Project is classified as rural. Because the Auer classification scheme requires more than 50 percent of the area within the approximately 2-mile (3-kilometer) radius around a proposed new source to be non-rural for an urban classification, the rural mode was used in the AERMOD modeling analyses.

4.1.2 Building Wake and Good Engineering Practice

The effects of building wakes (i.e., downwash) on plumes from the Project's operational sources were evaluated in accordance with USEPA guidance (USEPA, 1985). Data on the buildings on the Project Site that could potentially cause plume downwash effects for the sources were determined for different wind directions using the USEPA Building Profile Input Program–Prime (BPIP-Prime) (Version 04274).

As defined in *Guideline for Determination of Good Engineering Practice Stack Height* (USEPA, 1985), GEP is defined as the height necessary to ensure that emissions from a stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles.

All stacks in the HECA Project will be less than or equal to the GEP default height of 65 meters, except for the coal dryer, three flares, and the CO_2 vent. The heights of these stacks are as follows:

- Coal Dryer: 92.9 meters
- SRU Flare, Gasification Flare, Rectisol® Flare: 76.2 meters
- CO_2 Vent: 79.2 meters.

BPIP Prime has been run to determine the GEP height for each stack. The output of this model shows that the GEP for the three flares is 65 meters, for the coal dryer is 223.91 meters, and lastly the CO_2 vent is 223.90 meters. BPIP files will be provided with this application.

GEP is calculated based on the following equation:

$$Hg = H + 1.5 * L$$

where: Hg = GEP stack height (in meters)
H = height of the nearby structure (in meters)
L = lesser dimension of the height or projected width of the nearby structure (in meters)

The largest structure near these stacks is the gasifier building, which is 92.9 meters high and 27.7 × 82.8 meters in length × width, respectively. Therefore, L = 87.3 meters, H = 92.9 meters, and Hg = 223.9 meters.

The gasifier building is located at a distance within five times L (436.5 meters) from the CO_2 vent and the coal dryer; therefore, GEP for these stacks is calculated based on the gasifier building dimensions. The heights of the coal dryer and CO_2 vent are thus well below the GEP height of 223.9 meters.

The flares are located upwind of the gasification building along its shorter axis, thus L = 27.7 meters and Hg = 134.5 meters. The flares are not within 5 times L (138.5 meters) of the gasification structure or any other structure that is large enough to create downwash for the flares in BPIP Prime. It is important to note that the flares will be built at 76.2 meters tall for safety from a project engineering perspective. However, a 65-meter stack height, or GEP, was used to calculate specific effective stack heights for each flare modeling scenario based on the flare's heat release rate during that modeling scenario. The effective stack height is the height of the stack plus the height above the stack where the flare flame ends and a plume can begin. The effective stack parameters were calculated using the SCREEN3 technique, and were input into the AERMOD model (USEPA, 1995b). Therefore, the lower 65 meter stack height was used as the stack height in the calculation of the effective stack heights for the flares, rather than the actual stack height. Appendix D, Operational Criteria Pollutant Emissions, presents the effective stack parameters for the flares.

The results of the BPIP-Prime analysis were included in the AERMOD input files to enable downwash effects to be simulated. Input and output files for the BPIP-Prime analyses are included in the electronic files submitted with this Application.

4.1.3 Meteorological Data

Meteorological data suitable for direct input to AERMOD were obtained from the SJVAPCD website. Hourly surface data for calendar years 2006 through 2010 were obtained from the SJVAPCD for the Bakersfield Airport meteorological station, located on the northern end of the city of Bakersfield, within 20 miles (32.2 kilometers) east-northeast of the Project Site. These data have been pre-processed by the SJVAPCD with the Oakland upper-air data to create an input data set specifically tailored for input to AERMOD. The SJVAPCD prepared these data specifically for use at locations such as the Project Site.

The meteorological data recorded at Bakersfield Airport are acceptable for use at the Project Site for two reasons: proximity and terrain similarity. The Bakersfield Airport is the closest full-time meteorological recording station to the Project Site. The terrain immediately surrounding the Project Site can be categorized as a fairly flat, or gradually sloping rural area in a region with developed oil wells. The terrain around the Bakersfield Airport also consists of relatively flat, or gradually sloping rural or suburban areas. Thus, the land use and the location with respect to near-field terrain features are similar. Both are located in areas of medium surface roughness (as opposed to low surface roughness like bodies of water or grassy prairies, or high surface roughness like highly urbanized cities or forests). Both locations are on the valley floor and are at approximately the same elevation. Additionally, there are no significant terrain features separating the Bakersfield Airport from the Project Site that would cause significant differences in wind or temperature conditions between these respective areas. Therefore, the 5 years of meteorological data selected from the Bakersfield Airport were determined to be representative for the purposes of evaluating the Project's air quality impacts.

Seasonal and annual wind roses based on the 5 years of Bakersfield Airport surface meteorological data are provided in Appendix H, Seasonal and Annual Wind Roses. Winds for all seasons and all years blow predominantly from the sector between northwest and north, although the directional pattern is more variable during the fall and winter seasons.

4.1.4 Background Air Quality

Dispersion modeling to evaluate compliance with ambient air quality standards requires the use of measured air pollutant concentrations to account for the contributions of regional emissions, i.e., emission sources not explicitly included in the model simulations. This section describes the available monitoring data to represent "background" air quality in the Project Area, and explains the process by which data from specific monitoring stations were selected to represent background levels for each modeled pollutant and averaging time.

Air quality monitoring data representing existing air quality in the Project area were obtained from the USEPA AirData (USEPA, 2012) and the CARB-California Air Quality Data website (CARB, 2012). The maximum concentrations recorded at these monitoring stations over the

most recent available 3 year period of data collection were used as a conservative representation of existing air quality conditions at the Project Site. Use of this method effectively assumes that the *highest* recently recorded pollutant concentrations for each averaging period are occurring during *every* such period over the 5-year meteorological input record. This static high background is then paired with modeled results.

The monitoring station Kern County that is closest to the Project Site is the Shafter–Walker Street Station, within 13 miles (21 kilometers) from the Project Site. This station measures ozone (O_3) and NO_X/NO_2 concentrations, and is the most representative station to characterize background conditions for these pollutants near HECA. Further justification for use of the background data from this station can be found in Appendix I, NO_2 1 Hour Regional Analysis.

The Bakersfield ─ 5558 California Avenue station is the next closest station and the closest that measures all pollutants except SO_2 and CO. This station is located approximately 20 miles (32 kilometers) to the east of the Project site, and provides the best representation of the background levels for PM_{10} and $PM_{2.5}$ for the area near HECA. In addition, it is the only station that measures these pollutants with adequate data capture within the San Joaquin Valley portion of Kern County.

The Bakersfield ─ Golden State Highway station is the only station in Kern County that measures CO. This station was closed early in 2010; thus the most recent measurements available for this station are for 2007–2009, as 2010 data did not have suitable data capture. The only station in the SJVAB that monitors SO_2 is the CARB station at First Street in Fresno, located approximately 102 miles (164 kilometers) to the north. Sulfur dioxide data have only been recorded in Fresno County for 6 of the last 10 years (2003, 2007, 2008, 2009, 2010, 2011), a practice that is justified by the low levels that have been recorded for this pollutant where and when measurements have been made.

A summary of the highest measured pollutant concentrations over the most recent three years for which monitoring data are available at the stations discussed above is presented in Table 4-1. The tabulated values were used to represent background levels for the indicated pollutants and averaging times in the air quality impact analysis to evaluate compliance with National and California ambient air quality standards. The monitoring data indicate that the air quality in the Project Area is in compliance with all federal NAAQS and CAAQS for NO_2, CO, and SO_2. However, the NAAQS and/or the CAAQS are periodically exceeded in the Project Area for PM_{10}, and $PM_{2.5}$.

4.1.5 Receptor Locations

The property line extends around the perimeter of the Project Site and Controlled Area (see Figure 1-1, Project Site Plan and Vicinity The receptor grids used in the AERMOD modeling analyses for operational sources were as follows:

- 25-meter spacing along the property line and extending from the property line out 100 meters;

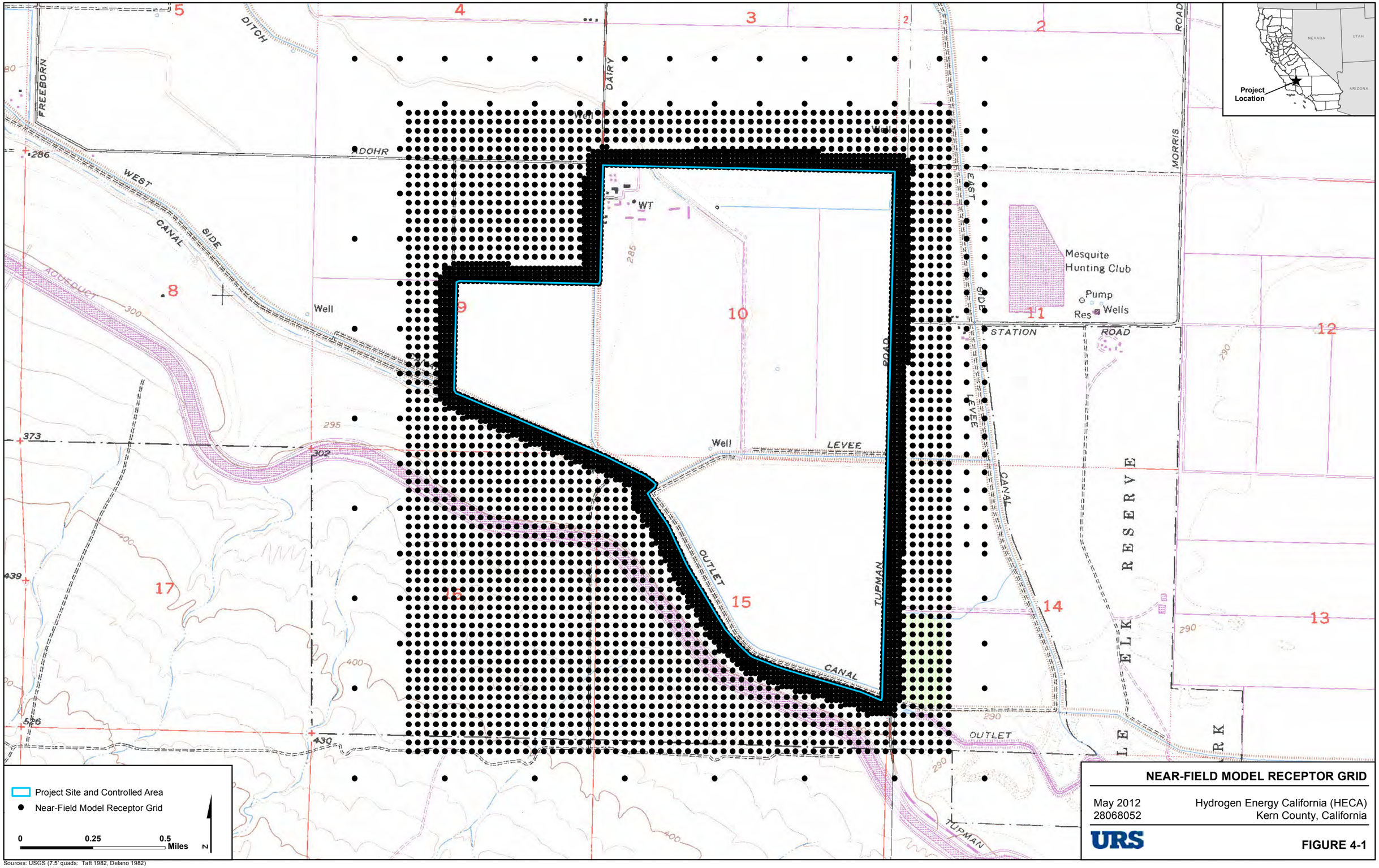
Table 4-1
Background Pollutant Levels Used in Ambient Air Quality Impact Analysis

Pollutant	Averaging Period	Background[1] (µg/m^3)	Monitoring Station Description[1, 2]	CAAQS (µg/m^3)	NAAQS (µg/m^3)
CO	1 hour	4,581	[a]	23,000	40,000
	8 hour	2,485	[a]	10,000	10,000
NO_2	1 hour CAAQS	140	[b]	339	--
	Annual	26	[b]	57	100
PM_{10}	24 hour	264	[c]	50	150
	Annual	54	[c]	20	--
$PM_{2.5}$	24 hour	196	[c]	--	35
	Annual	22	[c]	12	15
SO_2	1 hour	42	[d]	655	196
	3 hour	26	[d]	--	1,300
	24 hour	13	[d]	105	*revoked*

Source: HECA, 2012.
Notes:
[1] Background concentrations are maximum concentrations from the last 3 years of available USEPA AirData and/or CARB data. See note 2.
[2] Monitoring station/background concentration as described below:
[a] Bakersfield—Golden State Highway Monitoring Station, Maximum Concentration, 2007–2009
[b] Shafter–Walker Street Monitoring Station, Maximum Concentration, 2009–2011
[c] Bakersfield—California Avenue Monitoring Station, Maximum Concentration, 2008–2010
[d] Fresno—First Street Monitoring Station, Maximum Concentrations, 2007–2009 for 3-hour SO_2; 2009–2011 for 1-hour and 24-hour SO_2
CO = carbon monoxide H_2S = hydrogen sulfide
NO_2 = nitrogen dioxide NAAQS = National Ambient Air Quality Standards
PM_{10} = particulate matter less than 10 microns in diameter CAAQS = California Ambient Air Quality Standards
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
µg/m^3 = micrograms per cubic meter
SO_2 = sulfur dioxide N/A = not available

- 50-meter spacing from 100 to 250 meters beyond the property line;
- 100-meter spacing from 250 to 500 meters beyond the property line;
- 250-meter spacing from 500 meters to 1 kilometer beyond the property line;
- 500-meter spacing from 1 to 2 kilometers beyond the property line; and
- 1,000-meter spacing from 2 to 10 kilometers beyond the property line.

Figures 4-1, Near-Field Model Receptor Grid, and 4-2, Far-Field Model Receptor Grid, show the placement of near-field and far-field receptor points, respectively. Terrain heights at receptor grid points were determined from U.S. Geological Survey National Elevation Dataset files.



Sources: USGS (7.5' quads: Taft 1982, Delano 1982)

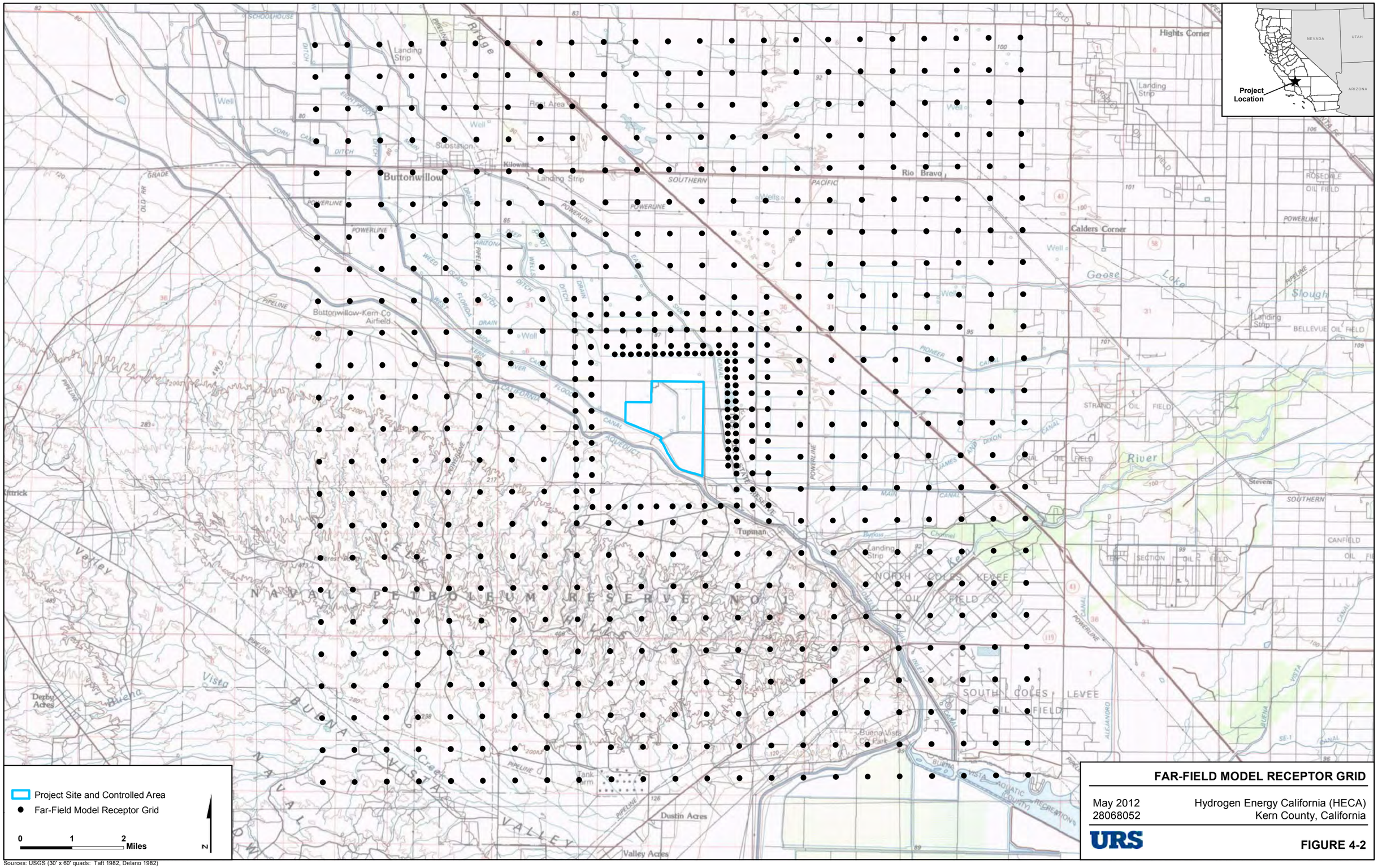
NEAR-FIELD MODEL RECEPTOR GRID

May 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 4-1



FAR-FIELD MODEL RECEPTOR GRID

May 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 4-2

During the refined modeling analysis for operational Project emissions, if a maximum predicted concentration for a particular pollutant and averaging time was located within the portion of the receptor grid with spacing greater than 25 meters, a supplemental dense receptor grid was placed around the original maximum concentration point, and the model was rerun. The dense grid used 25-meter spacing and extended to the next grid point in all directions from the original point of maximum concentration. The only dense refined receptor grid that was needed in the current modeling analysis occurred for 24-hour SO_2 operational modeling, where a dense grid was placed in the hills southwest of the Project site. Details may be seen in the model input files included in the electronic files submitted with this Application.

Consistent with accepted practice, this AERMOD receptor grid, with the additional dense nested grid points, was determined to best balance the need to predict maximum pollutant concentrations and optimizing model run time.

4.1.6 Sensitivity Modeling

For all pollutants and averaging times, screening modeling was performed with maximum emissions and the most conservative stack parameters for each source, regardless of whether all equipment will run at the same time in this worst-case stack parameter and emission configuration. This methodology was performed to determine conservative worst-case off-site impacts without the need of sensitivity modeling for each piece of equipment or time period. Normally, all sources will not run at the same time with their worst-case stack parameters and emissions. For example, the emergency ancillary equipment (generators, firewater pump) will not all be tested at the same time during a start-up sequence. However, if the most conservative impact scenario complied for the CAAQS and NAAQS, the equipment was kept in the modeling with maximum emissions and the most conservative stack parameters to eliminate the need for sensitivity modeling iterations.

More refined modeling was completed for several pollutants to more accurately depict the activities occurring concurrently for short averaging times. Sensitivity modeling was completed for CO 1-hour, and it was determined that the CTG/HRSG shut-down scenario (20 percent load burning natural gas) gave higher impacts than the CTG/HRSG starting up scenario. However, the maximum CO 8-hour impact was determined to occur during CTG/HRSG start-up mode when other sources are operating for that duration of time.

It was determined that the coal dryer gave higher short-term SO_2 impacts in operations mode than in start-up or shut-down mode, while all other maximum pollutant impacts for the coal dryer occurred during coal dryer start-up mode. Maximum PM_{10}, $PM_{2.5}$ 24-hour, and NO_2 1-hour CAAQS impacts occur for a plant start-up period rather than during operations or shut down mode. Finally, maximum NO_2 1-hour NAAQS impacts occur when the CTG/HRSG and coal dryer are operating in on-peak power mode rather than off-peak power mode.

Further details on worst-case modeling scenarios for each pollutant and averaging time are described in Section 4.1.9.2.

4.1.7 Fumigation Modeling

Fumigation can occur when a stable layer of air lies a short distance above the release point of an airborne plume and unstable air lies below. Especially on sunny mornings with light winds, the heating of the earth's surface causes a layer of turbulence, which grows in depth over time and may intersect an elevated pollutant plume. The transition from stable to unstable surroundings can rapidly draw a plume down to ground level and create relatively high pollutant concentrations for a short period. Typically, a fumigation analysis is conducted using the USEPA model SCREEN3 when the Project Site is rural and the stack height is greater than 10 meters.

A fumigation analysis was performed using SCREEN3 to calculate concentrations from inversion breakup fumigation. A unit emission rate was used (1 gram per second) in the fumigation modeling to obtain a maximum unit concentration (X/Q) and the model results were scaled to reflect expected Project emissions for each pollutant. Inversion breakup fumigation concentrations were calculated for 1-hour averaging times. Hourly model predictions are conservative, because inversion breakup fumigation is a transitory condition that would most likely affect a given receptor location for only a few minutes at a time.

Atmospheric conditions that could cause fumigation typically do not last for long periods, therefore due to the statistical nature of the NO_2 and SO_2 1-hour NAAQS, fumigation impacts were not compared to these standards. Fumigation impacts were compared to the NO_2 and SO_2 1-hour CAAQS, plus the 1-hour CO CAAQS.

Because SCREEN3 only models the impacts from one source, separate model runs were made for each of the main sources: the CTG/HRSG, coal dryer, tail-gas thermal oxidizer, and the nitric acid plant operating with parameters and emission rates used in the maximum short-term impact scenarios as described below in Section 4.1.9.2.

Maximum predicted fumigation impacts were determined for each source, then conservatively summed over all sources regardless of locations of the individual maxima. Further details on fumigation modeling can be found in Appendix J, Fumigation Modeling Results.

4.1.8 SIL Modeling

HECA is designated as a PSD source for three criteria pollutants: CO, NO_2, and PM_{10}. A project's impacts may be compared to the significant impact levels (SILs) as a screening modeling exercise that helps determine whether the project may cause or contribute to a violation of the NAAQS. If the modeled impact is below the SIL, then PSD increment or refined modeling is not required. CO 1-hour and 8-hour, PM_{10} 24-hour and annual, and NO_2 annual SILs are compared to the corresponding highest first high modeled values, while the NO_2 1-hour SIL is compared to the multiyear average first high 1-hour concentration at any receptor. Only stationary sources at the HECA Project were modeled to predict impacts for comparisons with the SILs; on-site mobile sources were excluded as they are not considered for PSD modeling.

4.1.9 NAAQS/CAAQS Modeling

Refined modeling analyses were performed to estimate off-site criteria pollutant impacts from operational emissions of the Project. The modeling was performed as described in the previous sections, using 5 years of hourly meteorological input data. Modeling was conducted for directly emitted NO_X, SO_X, CO, PM_{10}, and $PM_{2.5}$. No modeling was conducted for secondarily formed pollutants such as O_3 from NO_X and VOC precursors, or $PM_{2.5}$ from NO_X, SO_X, VOC, or NH_3 precursors. O_3 modeling is not required, because the annual Project emissions of VOC are less than the Significant Emission Rate (see Table 8-4). Models and modeling techniques to accurately estimate secondarily formed $PM_{2.5}$ from individual sources do not currently exist; thus, only directly emitted $PM_{2.5}$ was analyzed.

All new Project sources were modeled with their worst-case emission rates and stack parameters corresponding to each averaging time as outlined in Section 4.1.9.2. Emission rate calculations and assumptions used for all pollutants and averaging times are documented in Appendix D, Operational Criteria Pollutant Emissions.

4.1.9.1 NO_2 1-Hour NAAQS Modeling

NO_2 1-hour impacts from the Project stationary sources were predicted to be over the SIL; therefore, a refined NO_2 1-hour analysis was performed. Modeling protocols were prepared and discussed at length with USEPA and SJVAPCD in preparation for this analysis.

In addition to techniques described in the January 20, 2011 "Modeling Protocol for Parameter Selection Specific to the 1-Hour NO_2 NAAQS Regional Modeling for the Hydrogen Energy California (HECA) Project," the NO_2 1-hour NAAQS analysis was conducted incorporating guidance from three documents:

- "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" (USEPA, 2011);
- "Modeling Compliance of The Federal 1-Hour NO_2 NAAQS" (CAPCOA, 2011); and
- "Assessment of Non-Regulatory Option in AERMOD, Specifically OLM and PVMRM" (SJVAPCD, 2010).

A full description of the NO_2 1-hour NAAQS refined modeling methodology and analysis can be found in Appendix I, NO_2 1-Hour Regional Analysis.

4.1.9.2 Modeling Scenarios

4.1.9.2.1 Operations Emission Scenarios for Modeling

Worst-case impact scenarios do not necessarily align with maximum emission rates. Stack parameter variability for different equipment can change the overall estimated impacts on a per pollutant basis by changing plume rise. Another factor that determines maximum modeled impacts is whether multiple emission sources are operating simultaneously, and in which operating modes. The following subsections describe the modeling scenarios that were

determined to produce worst-case ground-level impacts for each pollutant and averaging time. Supporting calculations and documentation may be found in Appendix D, Operational Criteria Pollutant Emissions.

CO 1-hour

The maximum CO 1-hour impact scenario occurs when the CTG/HRSG is shutting down at 20 percent load burning natural gas, during which time the coal dryer and the auxiliary boiler are not operating. The Tail Gas Thermal Oxidizer and CO_2 vent both have process venting, while all three flares are in pilot mode. CO fugitives from the gasification, shift, AGR, SRU, and sour water areas are also included. Emergency equipment was not included in this scenario, as it will not be tested during shut-down. Mobile sources are not included in simulations to evaluate compliance with the NAAQS, while all mobile sources are included in the runs to assess compliance with the CAAQS.

CO 8-hour

The maximum CO 8-hour impact scenario occurs during a plant start-up when the CTG/HRSG and coal dryer are starting up, and a number of other sources are operating or starting up. For 0.5 hours the CTG/HRSG operates at 20 percent load on natural gas, for 2 hours the CTG/HRSG and coal dryer operate at 40 percent load on natural gas, and for the remaining portion of the 8-hour period the same emission units operate at 40 percent load on syngas. The Tail Gas Thermal Oxidizer is in start-up mode with maximum SRU waste gas disposal for the entire 8-hour duration. All flares are flaring in start-up mode. The Rectisol® and SRU flares are flaring at maximum hourly start-up rates. The gasification flare is flaring shifted syngas for 5 hours, with the remaining 3 hours at pilot operations. The CO_2 vent has maximum process venting, and the auxiliary boiler is also operating with maximum short-term emissions. The ammonia start-up heater is operating during 5 of the 8 hours in this start-up scenario. Emergency equipment was not included in this scenario, as it will not be tested during start-up. CO fugitives from the gasification, shift, AGR, SRU, and sour water areas are also included. Mobile sources are not included in model runs to predict impacts for comparison to the NAAQS, but are included in the simulations to evaluate compliance with the CAAQS.

NO_2 1-hour CAAQS

The maximum NO_2 1-hour CAAQS impact scenario occurs when the CTG/HRSG and coal dryer are starting up in 40 percent load natural gas mode, with the tail gas thermal oxidizer and ammonia start-up heater are also in start-up mode. All flares are in start-up mode with maximum heat release flaring. The auxiliary boiler and nitric acid plant are operating during this time at peak emission rates. Both emergency generators and the emergency diesel firewater pump are conservatively testing during this hour. It is important to note that all sources were modeled at maximum emission rates; sources with intermittent emissions were not represented using annualized 1-hour NO_X rates for the CEQA CAAQS modeling. Finally, all mobile sources are conservatively assumed to be operating during this time frame.

NO_2 1-hour SIL and NAAQS

The maximum NO_2 1-hour NAAQS impact scenario for the SIL and NAAQS analyses occurs when the CTG/HRSG and coal dryer are operating in on-peak power mode (turbine Case 1 - on-peak operation at ambient temperature 97F). Start-up emissions for the CTG/HRSG are limited to 105 hours per year, while shut-down emissions are limited to 18 hours per year. Start-up emissions for the coal dryer are limited to 104 hours per year, with shut-down emissions at 8 hours per year. Annualized maximum 1-hour NO_2 start-up/shut-down emission rates for these two sources are lower than their normal NO_2 1-hour rates, therefore, the maximum on-peak power NO_X 1-hour emission rates were used for the CTG/HRSG and coal dryer in the NO_2 1-hour SIL and NAAQS analyses. Similarly, the SRU flare and tail gas thermal oxidizer have maximum impacts during operations with pilot and process vent disposal, respectively, rather than during an annualized start-up period. The auxiliary boiler and nitric acid unit operations were included at their peak hourly emission rates. The Rectisol® and gasification flares were included with maximum annualized start-up flaring emission rates, which are higher than their normal rates in pilot mode. The ammonia plant start-up heater also was included with an annualized start-up 1-hour NO_2 emission rate. Finally, all three ancillary diesel engines including the two emergency diesel generators and firewater pump are included in the NO_2 1-hour SIL and NAAQS modeling with annualized emission rates. Mobile sources are not included in this modeling scenario.

NO_2 Annual

Maximum annual emissions for all NO_X emitting sources were included in the annual modeling scenarios. Maximum annual emissions include operating emissions plus all start-ups and shut-downs associated with each source that would occur over a one-year period. The CTG/HRSG and coal dryer use Case 5 (on-peak ambient temperature 65F) stack parameters, while the flares use effective stack parameters based on each flare's annualized heat release rate. All other sources are modeled with normal operating stack parameters. Mobile sources are not included in modeling for comparison to the NAAQS, while the maximum annual on-site mobile source emissions are included for comparison to the CAAQS.

PM_{10} and $PM_{2.5}$ 24-hour

The maximum PM_{10} and $PM_{2.5}$ 24-hour impact occurs when the CTG/HRSG and coal dryer are operating in start-up mode. Stack parameters for these sources used flow rates based on a start-up at 40 percent load on syngas, because most of the 24-hour start-up period would operate in this mode. Similarly, the tail gas thermal oxidizer and all flares were included with maximum emissions during start-up. All three cooling towers (ASU, Power Block, and Process) are operating at maximum 24-hour PM_{10} and $PM_{2.5}$ emission rates. The auxiliary boiler is not operating during this time, as it is not expected to operate while the CTG is operating. Both emergency generators are testing for 1 hour of the 24-hour period, while the emergency diesel firewater pump is testing for 2 hours during the 24-hour period. The emergency equipment maximum daily emissions were spread evenly across all hours in the day. The ammonia start-up heater is operating in start-up mode. All sources associated with the manufacturing plant with PM emissions are assumed to be operating, including the ammonium nitrate unit, and the urea pastillation stack; and all material handling sources are operating as well, which include all coal/

coke, urea, and gasification solids storage and handling systems. Emission source release points for material handling may be found in Appendix D, Operational Criteria Pollutant Emissions. Mobile sources are not included for comparison to the NAAQS, while the maximum daily number of on-site mobile sources is included for comparison to the CAAQS.

PM_{10} and $PM_{2.5}$ Annual

Maximum annual emissions from all PM emitting equipment were modeled for the annual modeling scenarios. Maximum annual emissions include normal operating emissions plus emissions from all annual start-ups and shut-downs associated with each source. The CTG/ HRSG and coal dryer use Case 5 (on-peak ambient temperature 65°F) stack parameters and emissions, while the flares use effective stack parameters based on each flare's annualized heat release rate. All other sources are modeled with normal operating stack parameters. Mobile sources are not included for comparison to the NAAQS, while the maximum annual number of mobile sources is included for comparison to the CAAQS.

SO_2 1-hour, 3-hour, 24-hour

Maximum SO_2 short-term impacts occur when the CTG/HRSG is operating at 80 percent load on natural gas, which is the highest SO_2 emission rate for the CTG/HRSG, conservatively mixed with the lowest exhaust flow rate (Case 2 – off-peak ambient temperature 97°F) that occurs during CTG/HRSG operations in off-peak power mode. Conversely, the coal dryer has the highest short-term SO_2 emissions during off-peak power, combined with the lowest exhaust flow rate. Although these two sources will not operate in their worst-case mode at the same time, SO_2 short term modeling was completed as described above to minimize the need for several sensitivity runs. The tail gas thermal oxidizer, the ammonia start-up heater, and all three flares are operating with maximum short-term start-up emission rates. Both emergency generators and the emergency diesel firewater pump are conservatively testing for all averaging times. The two emergency generators are both testing for 1 hour of the 24-hour period, while the emergency diesel firewater pump is testing for 2 hours during the 24-hour period. The maximum daily emissions of the emergency equipment were spread evenly across all hours in the day. All sources were modeled with maximum emission rates; sources with intermittent emissions did <u>not</u> use annualized 1-hour rates for the CEQA CAAQS or NAAQS 1-hour modeling. Mobile sources are not included for comparison to the NAAQS, while the maximum number of mobile sources is included for comparison to the CAAQS.

H_2S 1-hour CAAQS

The maximum H_2S 1-hour impact scenario occurs when the CO_2 vent is venting at maximum short-term H_2S emission rates. H_2S fugitives from the gasification, shift, AGR, SRU, and sour water areas are also included.

4.1.9.2.2 Commissioning Emission Scenarios for Modeling

Project engineers provided a number of commissioning emission scenario that represent the worst-case combinations of emissions from various sources during the commissioning period.

These emission scenarios were modeled with AERMOD to predict the maximum impact during commissioning.

Due to the short duration of commissioning activities, the variability of equipment usage, and the statistical nature of the NO_2 and SO_2 1-hour and $PM_{2.5}$ 24-hour NAAQS, commissioning impacts were compared to these standards. Commissioning impacts were compared instead to the NO_2 and SO_2 1-hour and $PM_{2.5}$ 24-hour CAAQS. Commissioning impacts will also be compared to the CO 1- and 8-hour, and SO_2 3- and 24-hour AAQSs.

Construction activities and commissioning activities overlap, although construction activities will be winding down and commissioning activities can be scheduled such that concurrent emissions from the combination of these activities will be minimal. Therefore, modeling was not conducted with the overlapping emissions. Appendix K, Commissioning Scenario Emissions and Modeling Results, presents the emissions from each source associated with each scenario. Below is a brief description of the scenarios examined.

Case 1

This scenario reflects the testing of either of the two emergency diesel generator engines while the Power Block cooling tower operates at reduced or no load. This scenario occurs early in the commissioning sequence when utility and support systems are being commissioned. The modeling analyses were conducted for SO_2 (1-hour and 24-hour), NO_2 (1-hour), CO (1-hour and 8-hour), and PM_{10} (24-hour).

Case A

This scenario reflects initial, "first fire" operation of the combustion turbine on natural gas at 20 percent load before the SCR and oxidation catalyst are operational. The Power Block cooling tower is also operating at reduced load. The modeling analysis was conducted for CO only, as this case represents the worst-case CO emission rates scenario, while the emissions of other pollutants are overlapped with other scenarios, such as other pollutant emissions, are the same or higher in other scenarios.

Case B

This scenario reflects operation of the combustion turbine on natural gas at 80 percent load before the SCR and oxidation catalysts are operational. This scenario is expected to occurring during tuning of the water injection rates for NO_X control. The modeling analyses were conducted for SO_2 and NO_2 since the emissions of other pollutants are overlapped with other scenarios. Case B is the worst-case NO_2 emission rate scenario.

Case A2

This scenario occurs during initial operation of the gasifier at 50 percent load while flaring sweet, unshifted syngas in the Gasification Flare. The gasifier operation is supported by Power Block operation (HRSG and coal dryer) on natural gas at 80 percent load, operation of all three cooling towers, and the Tail Gas Thermal Oxidizer. The modeling analyses were conducted for NO_2, CO, and PM_{10}. This case represents the worst-case PM_{10} emission scenario. SO_2

emissions are overlapped with, or less conservative, than other scenarios; therefore, this case was not modeled for SO_2.

Case B2

This scenario is similar to Case A2 and occurs later in the start-up sequence when shifted syngas is being sent to the Gasification Flare. This scenario anticipates a potential excursion in the SO_2 emissions from the Tail Gas Thermal Oxidizer that could occur briefly before the tail gas is recycled to the shift converters. All three cooling towers would be operated. The modeling analysis was conducted for SO_2 only, as this represents the worst-case SO_2 scenario for all averaging times, while the emissions of other pollutants are overlapped with other scenarios.

Case C2

This scenario occurs with gasifier operation at 50 percent load while flaring hydrogen-rich fuel gas in the Gasification Flare. This reflects a transitional period before the gas turbine can switch to hydrogen-rich fuel and CO_2 is vented before the CO_2 compressor is ready to send CO_2 to OEHI for EOR. The gasifier operation is supported by Power Block operation at 80 percent load on natural gas. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. The modeling analysis was conducted for CO only, since the emissions of other pollutants are overlapped with other scenarios.

Case D2

This scenario occurs with gasifier operation at 50 percent load while commissioning the hydrogen purification (PSA unit). A combination of mostly hydrogen-rich fuel plus PSA off-gas is being sent to the Gasification Flare. CO_2 is being sent to OEHI for EOR. The Power Block is operated at 80 percent load on natural gas. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. The modeling analysis was conducted for NO_2 only, since the emissions of other pollutants are overlapped with other scenarios.

Case E2

This scenario occurs with gasifier operation at 50 percent load and gas turbine operation at 40 percent load which requires some surplus hydrogen-rich fuel to be sent to the gasification flare. This would occur following the gas turbine switch from natural gas to hydrogen-rich fuel. CO_2 may need to be vented during this transition period. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. The modeling analysis was conducted for NO_2 and CO.

Case A3

This scenario occurs during commissioning of the Ammonia and Urea units when purified hydrogen is flared and purified CO_2 is vented before it can be converted to products. The CO content of the CO_2 stream is assumed to be higher than normal, but the flow rate is much lower than normal, so the emission rate is less than in normal operations. The Gasification Block and support systems are operating normally. The Power Block is operated at 100 percent load on

hydrogen-rich fuel. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. No modeling analysis was conducted since the emission rates of all pollutants in this Case are overlapped or covered with other scenario (specifically Case B3).

Case B3

This scenario is similar to Case A3, plus the ammonia synthesis start-up heater is also operating. The modeling analyses were conducted for SO_2, NO_2, and CO.

Case C3

This scenario occurs during commissioning of the Nitric Acid unit. The Gasification Block, Ammonia and Urea units are operating normally. The NO_X abator on the Nitric Acid unit is being commissioned and the NO_X level could potentially reach 200 ppm during the initial phase of NO_X tuning. The Power Block is operated at 100 percent load on hydrogen-rich fuel. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. The modeling analyses were conducted for NO_2 and PM_{10}.

4.1.9.3 SJVAPCD $PM_{2.5}$ Modeling

On October 4, 2011, SJVAPCD established *"Draft Procedures for Modeling $PM_{2.5}$"* (SJVAPCD, 2011). This guidance document followed direction from USEPA that the 1997 PM_{10} surrogacy policy that allowed use of PM_{10} source modeling to meet $PM_{2.5}$ compliance was no longer adequate. After April 21, 2010, permits under NSR and PSD programs were required to model $PM_{2.5}$ explicitly to demonstrate compliance. "*Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS"* (USEPA, 2010) is the first and only modeling guidance document that USEPA has released regarding techniques for performing $PM_{2.5}$ modeling analyses.

Kern County is designated nonattainment for both the federal and state $PM_{2.5}$ standards, and background monitored concentrations regularly far exceed federal and state standards. Therefore, $PM_{2.5}$ is not a PSD pollutant. The HECA Project is a minor source of $PM_{2.5}$ because it will emit less than 100 tons/year of $PM_{2.5}$ (SJVAPCD Rule 2201 Sections 3.24.1 and 3.18.1.4). The SJVAPCD modeling procedures establish a tiered approach for modeling $PM_{2.5}$. HECA falls under Tier I, or "Minor $PM_{2.5}$ NSR Projects Only." This tier requires only primary $PM_{2.5}$ to be modeled, and secondary formation of $PM_{2.5}$ is exempted until guidance is ultimately developed and provided by USEPA, and SJVAPCD has developed tools and guidance to address secondary formation from minor sources. Modeling of primary $PM_{2.5}$ was completed as specified in step 2 of Tier II in the SJVAPCD procedures. The primary $PM_{2.5}$ modeling used the 5-year meteorological data set concatenated into a single multi-year file to determine the maximum 24-hour 5-year average impact and each individual year of meteorological data to determine the maximum annual impact (SJVAPCD, 2011; USEPA, 2010). These concentrations were compared to the $PM_{2.5}$ Class II SILs of 0.3 microgram per cubic meter ($\mu g/m^3$) for annual and 1.2 $\mu g/m^3$ for 24-hour concentrations.

4.2 COMPLIANCE WITH AMBIENT AIR QUALITY STANDARDS

Air dispersion modeling was performed according to the methodology described in Section 4.1, Dispersion Modeling Methodology. This was done to evaluate the maximum increase in ground-level pollutant concentrations resulting from Project emissions for comparison with applicable SILs, and to compare the maximum predicted cumulative impacts, including background pollutant concentrations, with applicable short-term and long-term CAAQS and NAAQS.

In evaluating operational impacts, AERMOD was used to predict the increases in criteria pollutant concentrations at all receptor locations due to Project emissions only. Next, the maximum modeled incremental increases for each pollutant and averaging time were added to the maximum background concentrations, based on air quality data collected at the most representative monitoring stations during the last 3 years available (see Section 4.1.4). The resulting total pollutant concentrations were then compared with the most stringent CAAQS or NAAQS.

4.2.1 Operational Impacts

As described previously, emission scenarios used in the AERMOD simulations for the Project operations were selected to ensure that the maximum potential impacts would be addressed for each pollutant and averaging time corresponding to an AAQS. The emissions and scenarios used for each pollutant and averaging time are explained and quantified in Section 4.1.9.2, and in Appendix D, Operational Criteria Pollutant Emissions. This subsection describes the maximum predicted operational impacts of the Project for the operating conditions described in the modeling scenarios discussion above. Commissioning impacts, which will occur on a temporary, one-time basis and will not be representative of normal operations, were addressed separately, as described in Section 4.2.2.

Maximum operational impacts were compared to both SILs for applicable pollutants, and to the CAAQS and NAAQS. Several of the SILs, CAAQS, and NAAQS have distinctions between them regarding: the type of sources to be included in the comparison with the standard; and the exceedance criteria regarding whether the highest first high impact or a statistical modeled concentration is to be compared with each standard. The following subsections will summarize the modeled operational impacts from HECA.

4.2.1.1 SIL Modeling

HECA is a major PSD source for CO, NO_2, and PM_{10}. These pollutants are in attainment in the Project area, and annual HECA Project emissions are greater than the PSD Significant Emission Rates for these pollutants. Therefore, results of screening modeling to determine whether HECA operational impacts may cause or contribution to a violation of the NAAQS for these pollutants may be compared to their Class II SILs. If estimated Project impacts do not exceed the SILs, then the impacts are considered to not contribute significantly to any violation of the NAAQS, exempting HECA from a PSD increment analysis and a more refined cumulative analysis. For SIL modeling, only stationary sources of the proposed facility are included in the modeling

analyses. Table 4-2 summarizes maximum impacts due to HECA emissions compared with the applicable SILs.

Table 4-2
Project Operations Modeling Impacts Compared with Significant Impact Levels and Monitoring Concentrations

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Class II Significant Impact Level (SIL) ($\mu g/m^3$)	Significant Monitoring Concentration (SMC) ($\mu g/m^3$)
Operational Impacts				
CO	1 hour	2,625	2,000	N/A
	8 hour	368	500	575
NO_2	1 hour[2]	24	7.55	NA
	Annual	0.6	1	14
PM_{10}	24 hour	4.8	5	10
	Annual	0.7	1	N/A

Source: HECA, 2012.
Notes:
[1] Model predicted concentrations are the maximum impact from HECA stationary sources.
[2] The NO_2 1-hour concentration is the maximum first high concentration averaged over 5 years. The NO_2 1-hour SIL is interim, and was established in June 29, 2010.
N/A = not applicable
SMC = Significant Monitoring Concentration

PM_{10} 24-hour, PM_{10} annual, CO 8-hour, and NO_2 annual modeled impacts due to Project operations are less than the SILs. Although the maximum CO 1-hour impact is greater than the SIL of 2,000 $\mu g/m^3$, Section 4.2.1.4 presents refined modeling which shows that when the maximum modeled concentration from HECA operations are added to a conservatively high CO ambient background value, the impact is well below either the CO 1-hour CAAQS or NAAQS.

Section 4.1.9.2 described how HECA sources were modeled in comparison to the NO_2 1-hour interim SIL. In this initial impact analysis, several receptors exceeded the NO_2 1-hour SIL of 4 ppb (7.55 $\mu g/m^3$). Therefore, a cumulative assessment was completed following procedures outlined in several modeling guidance documents, agency discussions, and HECA modeling protocols. In the next section and in Appendix I, NO_2 1-Hour Regional Analysis, further information is given regarding the cumulative analysis completed for the 1-hour NO_2 NAAQS.

Significant Monitoring Concentrations (SMCs) are applicable to PSD pollutants only, and are compared to the same modeled pollutant concentrations from the Project as were compared to the SILs. SMCs are higher than SILs. HECA estimated impacts are lower than all applicable SMCs, therefore, monitoring is not required. No SMC exists for NO_2 1-hour.

4.2.1.2 PSD Increment Consumption

Federal PSD regulations require that proposed major sources, such as HECA, as well as other sources constructed since a specified "baseline date," not contribute to air pollution in excess of PSD increments in criteria pollutant attainment areas. These PSD increments are presented in Table 8-5. There are no PSD increments for CO 1-hour and 8-hour, and NO_2 1-hour.

The Project's maximum modeled air impacts for PM_{10} 24-hour and annual, and NO_2 annual are below the applicable SILs. Because the HECA NO_X and PM_{10} impacts will be less than the SILs, increment consumption will be insignificant and no preconstruction monitoring or additional impact analyses are required.

4.2.1.3 PSD Regional NO_2 Analysis

Because NO_2 impacts from HECA exceeded the 1-hour SIL, a cumulative impact assessment was completed to determine whether the Project would cause or contribute to any modeled violations of the NAAQS. HECA sources were combined with nearby sources and modeled in AERMOD with PVMRM, and hourly NO_2 ambient background concentrations were added to the hourly model predictions. Appendix I, NO_2 1-Hour Regional Analysis, contains the modeling approach, background air quality, emission sources modeled, and modeling result details for the regional analysis. Table 4-3 presents the highest of the modeled 5-year average of the 98th percentile of the maximum 1-hour daily concentration (design value) at any receptor, which complies with the 1-hour NO_2 NAAQS. This analysis demonstrates that HECA would not cause or contribute to any modeled violations, as the total design value predicted from the HECA sources, the nearby regional sources and background measured concentrations of NO_2 are less than the NAAQS.

4.2.1.4 NAAQS/CAAQS Modeling

For CEQA purposes mobile sources were included in the modeling conducted for compliance with the CAAQS. As noted in the footnotes of Table 4-3, many pollutants were modeled with both stationary and mobile sources and compared to both the CAAQS and NAAQS, thus the impacts for these pollutants are overestimated for the permitted stationary sources.

Table 4-3 summarizes the maximum predicted criteria pollutant concentrations due to Project emissions. This table also shows that the modeled impacts due to the Project emissions, in combination with conservative background concentrations, will not cause a violation of any CAAQS or NAAQS, and will not significantly contribute to the existing violations of the federal and state PM_{10} and $PM_{2.5}$ standards. In addition, as described later, all of the Project's operational emissions of PM_{10}, NO_X, VOCs, and SO_X will be offset to ensure a net air quality benefit. $PM_{2.5}$ emissions will be mitigated by the PM_{10} ERCs, because $PM_{2.5}$ is a subset of PM_{10}. All of the ERCs used to offset PM_{10} were from combustion sources; thus, the majority of the emission reductions are both PM_{10} and $PM_{2.5}$. Therefore, because all of the PM emissions will be offset, impacts of PM_{10} and $PM_{2.5}$ would be less than significant.

Table 4-3
AERMOD Modeling Results for Project Operations

Pollutant	Averaging Period	Modeled Impact (µg/m^3)	Background[1] (µg/m^3)	Monitoring Station Description[1, 2]	Total Predicted Concentration (µg/m^3)	CAAQS (µg/m^3)	NAAQS (µg/m^3)
Operational Impacts							
CO	1 hour[3]	2,663	4,581	[a]	7,244	23,000	40,000
	8 hour[3]	371	2,485	[a]	2,856	10,000	10,000
NO_2[8]	1 hour CAAQS[3]	185	140	[b]	325	339	--
	1 hour NAAQS[4]	126	[5]	[5]	126	--	188
	Annual CAAQS[6]	1.5	26	[b]	27	57	--
	Annual NAAQS[7]	0.6	26	[b]	27	--	100
PM_{10}	24 hour[3]	4.9	264	[c]	--	50	150
	Annual[6]	0.8	54	[c]	--	20	--
$PM_{2.5}$	24 hour[9]	3.1	196	[c]	--	--	35
	Annual[6]	0.6	22	[c]	--	12	15
SO_2	1 hour[3]	50	42	[d]	92	655	196
	3 hour[3]	29	26	[d]	55	--	1,300
	24 hour[3]	6	13	[d]	19	105	*revoked*
H_2S	1 hour[10]	23	N/A	N/A	23	42	--

Source: HECA, 2012.

Notes:

1 Background concentrations are maximum concentrations from the last 3 years of available USEPA AirData and/or CARB data. See note 2.

2 Monitoring station/background concentration as described below:

- [a] Bakersfield—Golden State Highway Monitoring Station, Maximum Concentration, 2007–2009
- [b] Shafter–Walker Street Monitoring Station, Maximum Concentration, 2009–2011
- [c] Bakersfield—California Avenue Monitoring Station, Maximum Concentration, 2008–2010
- [d] Fresno—First Street Monitoring Station, Maximum Concentrations, 2007–2009 for 3-hour SO_2; 2009–2011 for 1-hour and 24-hour SO_2

3 Maximum modeled short term concentration, includes HECA mobile sources and stationary sources

4 Regional NO_2 analysis modeling results. Modeled impact is the maximum 5-year average of 98th percentile of 1-hour daily maximum concentration. Modeled impact includes contributions from HECA, nearby sources and background concentrations. Excludes HECA mobile sources. Includes HECA stationary sources modeled at maximum normal operating emissions or annualized maximum intermittent operating emissions, whichever resulted in higher 1-hour emission rates. See Section 4.1.9.1 and Appendix I, NO_2 1-Hour Regional Analysis, for details and USEPA Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS, March 2011.

5 Hourly NO_2 background monitoring concentrations from the Shafter–Walker Street station were included in AERMOD analysis for the same years of meteorological data applied (2006–2010), data provided by SJVAPCD.

6 Maximum annual modeled concentration from any of the 5 years modeled, 2006–2010. Includes HECA mobile sources and stationary sources.

7 Maximum annual modeled concentration from any of the 5 years modeled: 2006–2010. Excludes mobile sources, includes HECA stationary sources

8 NO_2 modeling applied the PVMRM ozone limiting method with hourly ozone data from the Shafter–Walker Street monitoring station.

9 Maximum 5-year average first high daily concentration at any receptor. Excludes HECA mobile sources, includes HECA stationary sources.

10 Maximum modeled 1-hour concentration. Includes all HECA H_2S sources.

CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
SO_2 = sulfur dioxide
H_2S = hydrogen sulfide
NAAQS = National Ambient Air Quality Standards
CAAQS = California Ambient Air Quality Standards
µg/m^3 = micrograms per cubic meter
N/A = not available

Figure 4-3, Locations of Maximum Predicted Ground Level Pollutant Concentrations from HECA Operations, shows the locations of the maximum predicted operational impacts for all pollutants and averaging times. All peak annual impacts occur on the eastern boundary of the property line, along with the peak CO 1-hour impact, and the NO_2 1-hour CAAQS and NAAQS impacts. The peak PM_{10} and $PM_{2.5}$ 24-hour, H_2S 1-hour, and CO 8-hour all occur on the western boundary of the property line. All maximum SO_2 short term impacts occur in the hills to the southwest of the Project Site, approximately 3.5 kilometers from the southern boundary of the property line.

4.2.1.5 SJVAPCD $PM_{2.5}$ Analysis

$PM_{2.5}$ modeling was conducted per the draft modeling guidance from SJVAPCD. For the $PM_{2.5}$ SIL modeling, only permitted stationary sources were included in the modeling analyses. Table 4-4 shows that the primary $PM_{2.5}$ modeled concentrations exceed both the 24-hour and annual SILs, therefore, per SJVAPCD draft guidance, primary and secondary $PM_{2.5}$ emissions should be offset. HECA will fully offset all primary $PM_{2.5}$ and secondary $PM_{2.5}$ (oxides of nitrogen, and oxides of sulfur) emissions. HECA will use sulfur oxides (SO_X) ERCs to offset PM_{10} emissions on an interpollutant basis at a ratio of 1:1, as previously approved by SJVAPCD. Because the SO_X ERCs are from combustion sources, and the majority of combustion emissions contain particles smaller than 2.5 microns, they will also effectively offset the Project's $PM_{2.5}$ emissions. We believe that this should satisfy the offsetting provisions in the draft modeling guidance. Therefore, HECA demonstrates it will not cause or contribute significantly to a $PM_{2.5}$ violation.

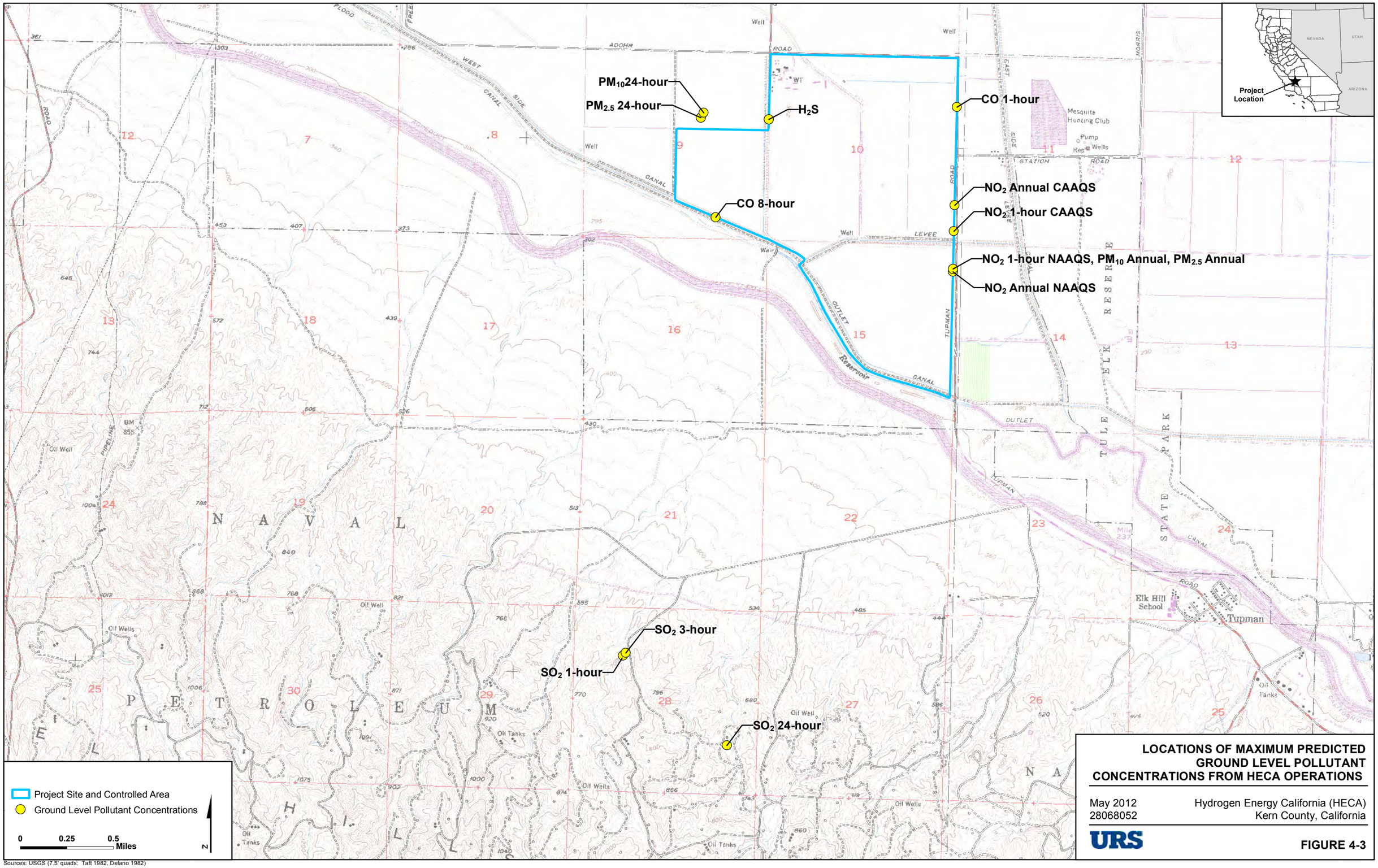
Table 4-4
AERMOD Modeling Results for $PM_{2.5}$ from HECA Operations

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Class II Significant Impact Level (SIL) ($\mu g/m^3$)
$PM_{2.5}$	24 hour[1]	3.1	1.2
	Annual[2]	0.6	0.3

Source: HECA, 2012.
Notes:
[1] Maximum annual modeled concentration from any of the 5 years modeled, 2006–2010. Excludes HECA mobile sources, includes HECA stationary sources.
[2] Maximum 5-year average first high daily concentration at any receptor. Excludes HECA mobile sources, includes HECA stationary sources.
$\mu g/m^3$ = micrograms per cubic meter
$PM_{2.5}$ = particulate matter 2.5 microns in diameter or less

4.2.1.6 Fumigation

The predicted peak concentrations from inversion fumigation from Project emissions, including background, are predicted to be below the applicable 1-hour CAAQS, and are presented in Table 4-5. Therefore, fumigation modeling complies with all applicable 1-hour ambient air quality standards.



LOCATIONS OF MAXIMUM PREDICTED GROUND LEVEL POLLUTANT CONCENTRATIONS FROM HECA OPERATIONS

May 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 4-3

Sources: USGS (7.5' quads: Taft 1982, Delano 1982)

Table 4-5
SCREEN3 Fumigation Modeling Results for Project Operations

Pollutant	Averaging Period	Maximum Modeled Impact (µg/m^3)	Background[1] (µg/m^3)	Monitoring Station Description[1,2]	Total Predicted Concentration (µg/m^3)	CAAQS (µg/m^3)	NAAQS (µg/m^3)
Fumigation Impacts							
CO	1 hour	282	4,581	[a]	4,863	23,000	40,000
NO_2	1 hour	43	140	[b]	183	339	N/A
SO_2	1 hour	2.7	42	[c]	45	655	N/A

Source: HECA, 2012.
Notes:
[1] Background concentrations are maximum concentrations from the last 3 years of available USEPA AirData and/or CARB data
[2] Monitoring station/background concentration as described below:
[a] Bakersfield—Golden State Highway Monitoring Station, Maximum Concentration, 2007–2009
[b] Shafter–Walker Street Monitoring Station, Maximum Concentration 2009–2011
[c] Fresno—First Street Monitoring Station, Maximum Concentration, 2009–2011 for 1 hour SO_2
N/A = not applicable
µg/m^3 = micrograms per cubic meter
CAAQS = California Ambient Air Quality Standards
NAAQS = National Ambient Air Quality Standards
CO = Carbon Monoxide
NO_2 = nitrogen dioxide
SO_2 = sulfur dioxide

4.2.2 Commissioning

Table 4-6 shows the results of the model simulations for the commissioning of the HECA Project. The tabulated impacts are the highest concentrations predicted for each pollutant and averaging time examined from all of the commissioning scenarios.

Table 4-6 demonstrates that when the maximum incremental commissioning impacts are added to applicable background concentrations and compared with the most stringent state or national AAQSs, no violations of the applicable standards for these pollutants are predicted to occur.

4.2.3 Odor Impacts

Modeling was conducted to determine the concentration of H_2S off-site. This modeling showed that the concentration predicted was less than the CAAQS (see Table 4-3), which is equivalent to the odor detection threshold; thus, H_2S odors will not be detectable beyond the property line.

Ammonia emissions from stationary and fugitive sources within the proposed HECA facility were included in the Health Risk Assessment (HRA) modeling for the Project, which is presented in Section 5, Health Risk Assessment. The Office of Environmental Health Hazard Assessment acute reference exposure level for ammonia is lower than the odor detection threshold for ammonia. Therefore, since the total acute health index was predicted to be less than significant, the ammonia concentration will be below the odor detection level and ammonia odors are not expected to be detectable beyond the property line.

Table 4-6
Commissioning Modeling Results

Modeling Scenario	Pollutant	Averaging Period	Maximum Estimated Impact (µg/m^3)	Background[1] (µg/m^3)	Monitoring Station Description[1]	Total Predicted Concentration (µg/m^3)	Most Stringent Standard (µg/m^3) [2]
Case A	CO	1-hour	1,975	4,581	[a]	6,556	23,000
		8-hour	801	2,485	[a]	3,286	10,000
Case B	NO_2[3]	1-hour	150	140	[b]	290	339
Case A2	PM_{10}	24-hour	3.4	264	[c]	NA	50
Case B2	SO_2	1-hour	97.4	42	[d]	139	655
		3-hour	37.5	26	[d]	64	1,300
		24-hour	7.5	13	[d]	20	105

Source: HECA 2012.
Notes:
[1] Background Concentrations are maximum concentrations from the last 3 years of available USEPA AirData and/or CARB data at the following stations
[a] Bakersfield—Golden State Highway Monitoring Station, Maximum Concentration 2007–2009
[b] Shafter–Walker Street Monitoring Station, Maximum Concentration 2009–2011
[c] Bakersfield—California Avenue Monitoring Station, Maximum Concentration 2008–2010
[d] Fresno—First Street Monitoring Station Maximum Concentrations, 2007–2009 for 3-hour SO_2, 2009–2011 for 1-hour and 24-hour SO_2
[2] Although there are NAAQS for SO_2 1-hour, NO_2 1-hour, and $PM_{2.5}$ 24-hour, these are statistical standards therefore impacts from commissioning activities are only compared to the CAAQS due to the infrequent nature of the commissioning events.
[3] NO_2 modeling for commissioning was conducted with the PVMRM algorithm.
CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
SO_2 = sulfur dioxide
µg/m^3 = micrograms per cubic meter

4.3 IMPACTS FOR NON-ATTAINMENT POLLUTANTS AND THEIR PRECURSORS

The emission offset program described in the SJVAPCD rules was developed to facilitate net air quality improvement when new sources locate within the District. Project impacts of non-attainment pollutants and their precursors in excess of specified thresholds will be fully mitigated by emission offsets, as outlined in Section 7, Emission Reduction Credits Package. The emission reductions associated with these offsets have not been accounted for in the modeled impacts noted above. Thus, the impacts indicated in the foregoing presentation of model results for the Project may be significantly overestimated.

To assess the potential impact of the Project on public health, a human HRA was performed, based on the Project's emissions of HAPs and TACs. The federal Clean Air Act (CAA) regulates HAPs, airborne pollutants that are known to have adverse human health effects. Unlike criteria pollutants, HAPs do not have adopted ambient air quality standards. HAPs have been regulated at the federal level since the CAA of 1977 under 40 CFR, Parts 61 and 63. Similar to the federal program, the California Clean Air Act regulates TACs, a class of airborne pollutants similar to the federal HAPs. Pollutants addressed under this section are generally referred to as TACs, except where federal designation is required.

This section describes the methodology and results of the HRA for the Project. The purpose of the HRA is to evaluate potential public exposure and adverse health effects due to TAC emissions associated with Project operations. For the purposes of the HRA, impacts were determined outside of both the Project Site and the Controlled Area (see Figure 1-1, Project Site Plan and Vicinity). HECA will own both the Project Site and the Controlled Area, and will have control over public access and future land use.

5.1 SENSITIVE RECEPTORS

The CEC defines sensitive receptors as infants and children, the elderly, the chronically ill, and any other members of the general population who are more susceptible to the effects of exposure to environmental contaminants than the population at large. For the purposes of this analysis, sensitive receptors are defined as the locations occupied by groups of individuals that may be more susceptible than the general population to health risks from a chemical exposure. Sensitive receptor locations therefore include schools (public and private), day-care facilities, convalescent homes, parks, and hospitals.

Two sensitive receptors exist within 6 miles of the Project (6 miles is the extent of the modeling receptor grid): Elk Hills elementary school, 1.3 miles to the southeast; and the Tule Elk State Natural Reserve, located 1,700 feet to the east of the Project Site and Controlled Area. Figure 5-1, Sensitive and Residential Receptors Located Near the Project Site, shows the location of these sensitive receptors, plus the locations of the nearest residences. A total of 118 residences near the Project Site were included in the modeling. The closest residential neighborhood is in the unincorporated community of Tupman, approximately 2 miles southeast of the Project boundary. There are also additional single-family residences in the immediate Project vicinity, including residences approximately 1,400 feet to the east and 3,300 feet to the southeast of the Project Site. The HRA approach treats all receptors as sensitive receptors.

5.2 PUBLIC HEALTH IMPACT ASSESSMENT APPROACH

This section describes the evaluation of potential public health risks due to operation of the Project, as well as the methodology and results of the HRA. A significant impact is defined as a maximum incremental cancer risk greater than 10 in 1 million, a chronic total hazard index (THI) greater than 1.0, or an acute THI greater than 1.0. Also, uncertainties in the HRA are discussed, and other potential health impacts of the Project are described.

The potential human health risks posed by the Project's emissions were assessed by following the Office of Environmental Health Hazard Assessment (OEHHA) Air Toxics Hot Spots Program Risk Assessment Guidelines (Cal/EPA/OEHHA, 2003). The OEHHA guidelines were developed to provide risk assessment procedures, as required under the Air Toxics Hot Spots Information and Assessment Act of 1987, Assembly Bill 2588 (Health and Safety Code §§ 44360 *et seq*.). The Hot Spots law established a statewide program to inventory air toxics emissions from individual facilities, as well as guidance for execution of risk assessments and requirements for public notification of potential health risks.

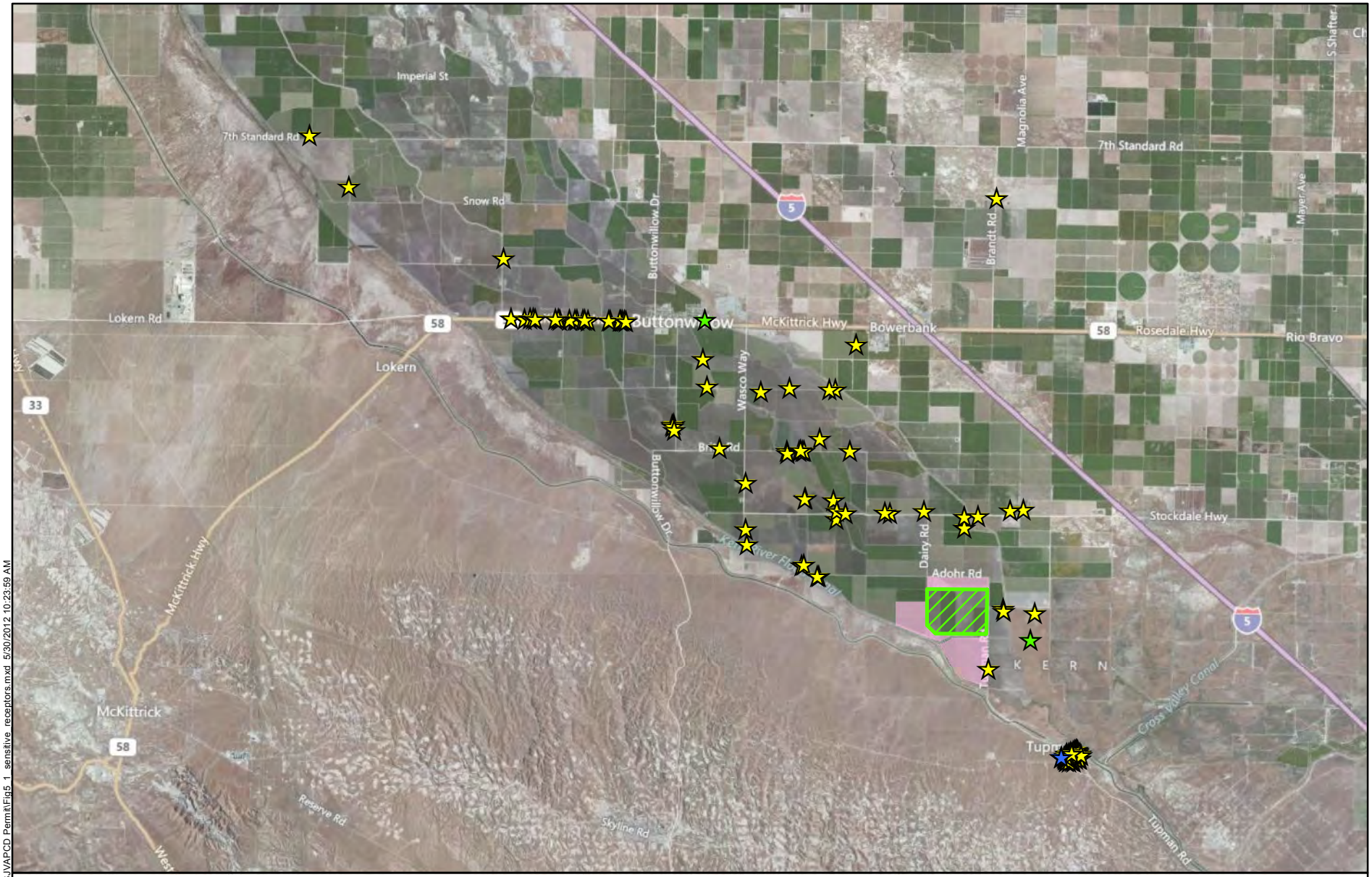
As recommended by the OEHHA guidelines, the CARB Hotspots Analysis and Reporting Program (HARP) was used to perform an OEHHA Tier 1 HRA for the Project. HARP includes two modules: a dispersion module, and a risk module. The HARP dispersion module incorporates the USEPA Industrial Source Complex Short Term 3rd version (ISCST3) air dispersion model. The HARP risk module implements the latest Risk Assessment Guidelines developed by OEHHA. For consistency with the criteria pollutant modeling, the dispersion modeling was conducted with AERMOD software. CARB has created a software package called HARP On-Ramp to convert AERMOD dispersion results into a format that can be read into the HARP risk module. Thus, HARP with AERMOD was used for this HRA.

The HRA was conducted in four steps using the HARP:

1. Hazard identification and emission quantification
2. Exposure assessment
3. Dose-response assessment
4. Risk characterization.

First, hazard identification was performed to determine the potential health effects that could be associated with Project emissions. The purpose was to identify whether pollutants emitted during Project operation could be characterized as potential human carcinogens, or associated with other types of adverse health effects. Based on OEHHA guidelines, a list of pollutants with potential cancer and non-cancer health effects associated with the emissions from the Project is provided in Table 5-1, Summary of Operational TACs and Toxicity Values Used to Characterize Health Risks.

Second, an exposure assessment was conducted to estimate the extent of public exposure to Project emissions. Public exposure is quantified based on the predicted maximum short- and long-term ground-level concentrations resulting from Project emissions, the exposure pathway(s), and the duration of exposure to those emissions. Dispersion modeling was performed using the AERMOD model to estimate the highest ground level 1-hour, 8-hour, and annual concentrations near the Project Site and Controlled Area boundary. The AERMOD model was run with unit emission rate (1 gram per second) for each source to calculate the concentration of TACs per unit emission rate from each source, known as "X/Q," for 1-hour and annual averaging times per receptor. AERMOD was run again to obtain the 8-hour concentrations per receptor for substances with 8-hour acute reference exposure levels (RELs). The 1-hour and annual X/Q values were processed in the HARP On-Ramp program for input into the HARP program. The methods used in the dispersion modeling were consistent with the approach described in Section 4, and the modeling protocols submitted for the Project to CEC, USEPA, and SJVAPCD.



Project Site

Controlled Area

Dwelling

Park/Reserve

School

N

0 1 2 Miles

SENSITIVE AND RESIDENTIAL RECEPTORS NEAR THE PROJECT SITE

May 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 5-1

Source: Aerial Imagery, (c) 2010 Microsoft Corporation and its data suppliers.

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Table 5-1
Summary of Operational TACs and Toxicity Values Used to Characterize Health Risks

Compound	CAS #	Acute REL (µg/m^3)	8-Hour Inhalation REL (µg/m^3)	Chronic REL (µg/m^3)	Inhalation Cancer Potency Factor (mg/kg-day)$^{-1}$
3-Methylchloranthrene	56-49-5	–	–	–	2.2E+01
7,12-Dimethylbenz(a)anthracene	57-97-6	–	–	–	2.5E+01
Acetaldehyde	75-07-0	4.7E+02	3.0E+02	1.4E+02	1.0E-02
Ammonia*	7664-41-7	3.2E+03	–	2.0E+02	–
Arsenic	7440-38-2	2.0E-01	1.5E-02	1.5E-02	1.2E+01
Benz(a)anthracene	56-55-3	–	–	–	3.9E-01
Benzene	71-43-2	1.3E+03	–	6.0E+01	1.0E-01
Benzo(a)pyrene	50-32-8	–	–	–	3.9E+00
Benzo(b)fluoranthene	205-99-2	–	–	–	3.9E-01
Benzo(k)fluoranthene	207-08-9	–	–	–	3.9E-01
Beryllium	7440-41-7	–	–	7.0E-03	8.4E+00
Cadmium	7440-43-9	–	–	2.0E-02	1.5E+01
Carbon Disulfide	75-15-0	6.2E+03	–	8.0E+02	–
Chromium, (hexavalent)	18540-29-9	–	–	2.0E-01	5.1E+02
Chrysene	218-01-9	–	–	–	3.9E-02
Copper*	7440-50-8	1.0E+02	–	–	–
Cyanides	57-12-5	3.4E+02	–	9.0E+00	–
Dibenzo(a,h)anthracene	53-70-3	–	–	–	4.1E+00
Dichlorobenzene	106-46-7	–	–	8.0E+02	4.0E-02
Diesel Particulate Matter*	DPM	–	–	5.0E+00	1.1E+00
Fluoride*	–	2.4E+02	–	1.3E+01	–
Formaldehyde	50-00-0	5.5E+01	9.0E+00	9.0E+00	2.1E-02
Hexane	110-54-3	–	–	7.0E+03	–
Hydrochloric Acid	7647-01-0	2.1E+03	–	9.0E+00	–
Hydrogen Fluoride (Hydrofluoric Acid)	7664-39-3	2.4E+02	–	1.4E+01	–
Hydrogen Sulfide	7783-06-4	4.2E+01	–	1.0E+01	–
Indeno(1,2,3-cd)pyrene	193-39-5	–	–	–	3.9E-01
Lead	7439-92-1	–	–	–	4.2E-02
Manganese	7439-96-5	–	1.7E-01	9.0E-02	–
Mercury	7439-97-6	6.0E-01	6.0E-02	3.0E-02	–

Source: HECA 2012; OEHHA/CARB (2011)
Notes:
CAS # = Chemical Abstracts Service Registry Number
DPM = diesel particulate matter
REL = reference exposure level
µg/m^3 = micrograms per cubic meter
mg/kg-day = milligrams per kilogram per day
* Denotes pollutants that are not listed as Federal HAPs.

Third, a dose-response assessment was performed in HARP that incorporated the maximum 1-hour and annual ground-level concentrations predicted by AERMOD to characterize the relationship between pollutant exposure, and the potential incidence of an adverse health effect in the exposed populations. The dose-response relationship is expressed in terms of potency factors for cancer risk and RELs for acute and chronic non-cancer risks. The OEHHA guidelines provide potency factors and RELs for an extensive list of TACs, including those listed in Table 5-1. All exposure pathways were included in this analysis; except the beef/dairy and fish ingestion and drinking water consumption pathways, no unenclosed water storage reservoirs or cattle exist near the site. For the calculation of cancer risk, the duration of exposure to Project emissions was assumed to be 24 hours per day for 70 years, at all receptors. The cancer risk was calculated in HARP using the Derived (Adjusted) Method, and the chronic THI was calculated in HARP using the Derived (OEHHA) Method. For the calculation of acute risk, it was assumed that exposure occurs over a 1-hour period. Calculation of chronic risk assumes an exposure over a 1-year period. The risk calculation for the maximally exposed individual worker (MEIW) assumed that the worker would be present at that location for 8 hours per day, 5 days per week, 49 weeks per year, for 40 years (default HARP worker adjustment).

Fourth, risk characterization was performed to integrate the health effects and public exposure information, and provide quantitative estimates of health risks resulting from Project emissions. Risk modeling was performed using HARP to estimate cancer and non-cancer health risks due to Project operational emissions. The HARP model uses OEHHA equations and algorithms to calculate health risks based on input parameters such as emissions, “unit” ground level concentrations, and toxicological data.

AERMOD modeling was conducted to determine the ground-level 8-hour concentrations of acetaldehyde, arsenic, formaldehyde, manganese, and mercury. These concentrations were then divided by the appropriate RELs and summed by target organ to determine the total acute health index for TACs with 8-hour RELs.

Health risks were calculated for the areas that have public access; thus, all areas outside the Project Site and Controlled Area were included in the HRA.

Detailed descriptions of the model input parameters and results of the HRA are given in Section 5.4. All HARP and AERMOD model files are provided electronically with this AFC Amendment.

5.3 OPERATIONAL-PHASE AIR TOXICS EMISSIONS

5.3.1 Stationary Sources

The following operational sources associated with the Project will generate emissions of TACs. These emissions will be generated from the combustion of syngas, natural gas, diesel fuel, and process vent gases. In addition, emissions will be generated from the operation of the cooling towers, the Manufacturing Complex, and fugitives associated with leaks in the piping and components from each process area.

Power Block	Gasification Block	Ancillary Equipment	Manufacturing Complex
• Combustion Turbine (MHI 501GAC®) • Power Block Cooling Tower	• Coal Dryer • Auxiliary Boiler • Gasification Flare • Sulfur Recovery Unit (SRU) Flare • Rectisol® Flare • Tail Gas Thermal Oxidizer • ASU and Process Cooling Towers • Carbon Dioxide Vent	• 2 Emergency Diesel Generators • Emergency Diesel Firewater Pump	• Nitric Acid Unit • Urea Absorbers • Urea Pastillation • Ammonium Nitrate Unit • Ammonia Synthesis Unit Start-up Heater

A summary of the TACs that are expected to be emitted as a result of operations and the corresponding toxicity values used for evaluation are shown in Table 5-1.

Table 5-2, HECA Total Toxic Air Contaminant Annual Emission Rates, outlines the estimated TAC annual emission rates for each source listed above. These rates were determined based on the size, capacity, and expected annual operating hours of each piece of equipment. TAC emission estimates were made using the following emission factors and assumptions for each source.

The most significant emission source of the Project will be the CTG/HRSG train. Exhaust gas from the turbine section is ducted through the HRSG to generate high-energy steam, which produces additional electricity in the steam turbine. Some of the exhaust gas is also ducted from the HRSG to the gasification block to dry the feed, and will be discharged at the coal-dryer stack in that process block. Remaining exhaust gas at the HRSG is discharged through the HRSG stack. The combustion system is designed for operation on hydrogen-rich fuel. Natural gas is used during start-up and shut-down of the combustion turbine, and during periods of unplanned equipment outages (up to 2 weeks per year).

TAC emission factors for the CTG/HRSG and coal dryer were obtained from the Wabash River Generating Station test data and the National Energy Technology Laboratory, U.S. DOE, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report*, December 2002. These are considered the most representative data available because of the use of similar technology in operation. Ammonia slip from the SCR is limited to 5 ppmv dry at 15 percent O_2. Mercury emissions are based on the mercury content in the feedstock, mercury removal efficiency in the syngas cleanup, and mercury removal efficiency in the coal-dryer exhaust. Mercury will be removed downstream of the Sour Shift and Low Temperature Gas Cooling units, and at the coal dryer using activated carbon.

CTG/HRSG and coal-dryer TAC emissions were estimated based on operating conditions firing syngas. Hourly emission rates were calculated based on the maximum hourly heat input required

for operation at 100 percent load, which is expected to occur under an ambient temperature of 97°F with duct firing. Annual emissions rates were calculated based on 100 percent load at annual average temperature of 65°F with duct firing. Annual operating hours include operations on syngas with duct firing, start-up, shut-down, and backup operation on natural gas. Emissions were conservatively based on all hours of operation applying the syngas emission factors.

Emission factors for TACs from the natural gas external combustion sources, the auxiliary boiler, tail gas thermal oxidizer, gasifier flare, SRU flare, Rectisol® flare, and Ammonia Synthesis Start-up Heater are from USEPA AP-42 Section 1.4 (USEPA, 1995c).

Auxiliary boiler hourly emission rates were calculated based on the required standard cubic feet of natural gas required per hour based on boiler design. Ammonia emissions were calculated based on a stack exhaust limit of 5 ppm due to slip from the SCR. Annual emission rates were calculated based on a 25 percent capacity factor.

Tail gas thermal oxidizer hourly emission rates were calculated based on the standard cubic feet of natural gas required per hour, based on oxidizer design for a combination of pilot and start-up operations. Annual emission rates were calculated based on 8,760 hours per year of operations plus 48 hours per year of start-up.

Gasification flare hourly emissions were calculated based on the hourly heat input rate required for pilot flame operation and the heat content of the fuel flared during the peak hour of start-up or shut-down activities; contributions of both were accounted for in the hourly rates. Annual emission rates were calculated assuming 8,760 hours per year of pilot operation, and approximately 28 hours per year of flaring events associated with plant start-up and shut-down.

SRU flare hourly emissions were calculated based on the hourly heat input rate required for pilot flame operation and the heat content required for assist gas during a start-up; contributions of both were accounted for in the hourly rates. Annual emission rates were calculated assuming 8,760 hours per year of pilot operation and approximately 40 hours per year of start-up flaring.

Rectisol® flare hourly emissions were calculated based on the hourly heat input rate required for pilot flame operation, and the heat content required for assist gas during a start-up or shut-down; contributions of both were accounted for in the hourly rates. Annual emission rates were calculated assuming 8,760 hours per year of pilot operation, and 40 hours per year of start-up and shut-down flaring.

Ammonia Synthesis Start-up Heater hourly emission rates were calculated based on the required standard cubic feet of natural gas required per hour based on heater design. Annual emission rates were calculated based on the usage of 140 hours for start-up operation per year.

Cooling tower (Power Block, ASU, and Process Area) TAC emissions were based on engineering calculations using the contaminant concentrations in the raw water, the number of cycles of concentration in the cooling towers, and the assumed drift rate. Arsenic, fluoride, manganese, and selenium concentrations in the raw water were based on analytical test results. Copper concentrations in the raw water were based on one-half of the stated detection limit.

Table 5-2
HECA Total Toxic Air Contaminant Annual Emission Rates

Compound	CAS #	Annual Rate (TPY)	CTG/ Stack (lb/yr)	Coal Dryer Stack (lb/yr)	Cooling Tower (Power Block) (lb/yr)	Cooling Tower (Process Area) (lb/yr)	Cooling Tower (ASU) (lb/yr)	Auxiliary Boiler (lb/yr)	Ammonia Plant Start-up Heater (lb/yr)	Emergency Generators (lb/yr)	Fire Water Pump (lb/yr)	Gasification Flare (lb/yr)	SRU Flare (lb/yr)	Rectisol Flare (lb/yr)	TG Thermal Oxidizer (lb/yr)	CO_2 Vent (lb/yr)	Manu-facturing Complex (lb/yr)	On-Site Truck (lb/yr)	On-Site Train (lb/yr)	Fugitives (lb/yr)
Acetaldehyde	75-07-0	2.15E-02	3.66E+01	6.46E+00																
Ammonia*	7664-41-7	1.57E+02	1.56E+05	2.75E+04				1.03E+03									1.18E+05			1.14E+04
Antimony	7440-36-0	1.32E-02	2.24E+01	3.95E+00																
Arsenic	7440-38-2	2.88E-02	4.88E+01	8.61E+00	5.33E-02	8.70E-02	2.40E-02	8.89E-02	1.47E-03			1.43E-02	7.75E-04	3.78E-03	2.13E-02					
Benzene	71-43-2	2.94E-02	4.88E+01	8.61E+00				9.33E-01	1.54E-02			1.50E-01	8.14E-03	3.97E-02	2.24E-01					
Beryllium	7440-41-7	3.11E-03	5.28E+00	9.33E-01				5.33E-03	8.80E-05			8.56E-04	4.65E-05	2.27E-04	1.28E-03					
Cadmium	7440-43-9	1.15E-01	1.95E+02	3.44E+01				4.89E-01	8.07E-03			7.85E-02	4.26E-03	2.08E-02	1.17E-01					
Carbon Disulfide	75-15-0	5.50E-01	9.35E+02	1.65E+02																
Carbonyl Sulfide	463-58-1	2.69E+00														5.32E+03				5.94E+01
Chromium	7440-47-3	6.55E-03	1.04E+01	1.83E+00				6.22E-01	1.03E-02			9.99E-02	5.42E-03	2.64E-02	1.49E-01					
Chromium (hexavalent)	18540-29-9	1.83E-03	3.11E+00	5.49E-01																
Cobalt	7440-48-4	3.14E-03	5.28E+00	9.33E-01				3.73E-02	6.16E-04			5.99E-03	3.25E-04	1.59E-03	8.95E-03					
Copper*	7440-50-8	2.93E-04			1.03E-02	1.69E-02	4.66E-03	3.78E-01	6.23E-03			6.06E-02	3.29E-03	1.61E-02	9.06E-02					
Cyanides	57-12-5	6.87E-02	1.16E+02	2.04E+01																1.15E+00
Fluoride*	1101	1.44E-03			9.31E-01	1.52E+00	4.20E-01													
Formaldehyde	50-00-0	2.28E-01	3.46E+02	6.10E+01				3.33E+01	5.50E-01			5.35E+00	2.91E-01	1.42E+00	7.99E+00					
Hexane	110-54-3	5.87E-01						8.00E+02	1.32E+01			1.28E+02	6.97E+00	3.40E+01	1.92E+02					
Hydrochloric Acid	7647-01-0	1.55E-01	2.64E+02	4.66E+01																
Hydrogen Fluoride (hydrofluoric acid)	7664-39-3	5.98E-01	1.02E+03	1.79E+02																
Hydrogen Sulfide	7783-06-4	2.64E+00														3.01E+03				2.28E+03
Lead	7439-92-1	6.70E-03	1.14E+01	2.01E+00																
Manganese	7439-96-5	1.67E-02	2.11E+01	3.73E+00	2.66E+00	4.35E+00	1.20E+00	1.69E-01	2.79E-03			2.71E-02	1.47E-03	7.18E-03	4.05E-02					
Mercury	7439-97-6	7.71E-03	1.03E+01	4.98E+00				1.16E-01	1.91E-03			1.85E-02	1.01E-03	4.91E-03	2.77E-02					
Methanol	67-56-1	7.09E+00																		1.42E+04
Methyl Bromide (Bromomethane)	74-83-9	5.70E-01	9.70E+02	1.71E+02																
Methylene Chloride (Dichloromethane)	75-09-2	2.63E-02	4.47E+01	7.89E+00																
Naphthalene	91-20-3	3.01E-02	5.08E+01	8.97E+00				2.71E-01	4.47E-03			4.35E-02	2.36E-03	1.15E-02	6.50E-02					
Nickel	7440-02-0	5.35E-03	7.93E+00	1.40E+00				9.33E-01	1.54E-02			1.50E-01	8.14E-03	3.97E-02	2.24E-01					
Nitric Acid*	7697-37-2	8.19E-01																		1.64E+03
Phenol	108-95-2	4.40E-01	7.48E+02	1.32E+02																

Table 5-2
HECA Total Toxic Air Contaminant Annual Emission Rates (Continued)

Compound	CAS #	Annual Rate (TPY)	CTG/ Stack (lb/yr)	Coal Dryer Stack (lb/yr)	Cooling Tower (Power Block) (lb/yr)	Cooling Tower (Process Area) (lb/yr)	Cooling Tower (ASU) (lb/yr)	Auxiliary Boiler (lb/yr)	Ammonia Plant Start-up Heater (lb/yr)	Emergency Generators (lb/yr)	Fire Water Pump (lb/yr)	Gasification Flare (lb/yr)	SRU Flare (lb/yr)	Rectisol Flare (lb/yr)	TG Thermal Oxidizer (lb/yr)	CO_2 Vent (lb/yr)	Manu-facturing Complex (lb/yr)	On-Site Truck (lb/yr)	On-Site Train (lb/yr)	Fugitives (lb/yr)
Propylene*	115-07-1	6.33E+00																		1.27E+04
Selenium	7782-49-2	6.77E-03	1.14E+01	2.01E+00	4.43E-02	7.23E-02	2.00E-02	1.07E-02	1.76E-04			1.71E-03	9.30E-05	4.53E-04	2.56E-03					
Sulfuric Acid and Sulfates*	7664-93-9	1.14E+00	1.93E+03	3.41E+02																
Toluene	108-88-3	1.50E-03	6.71E-01	1.18E-01				1.51E+00	2.49E-02			2.43E-01	1.32E-02	6.42E-02	3.62E-01					
Vanadium*	7440-62-2	7.50E-04						1.02E+00	1.69E-02			1.64E-01	8.91E-03	4.34E-02	2.45E-01					
Diesel Particulate Matter*	DPM	7.72E-02								4.51E+01	1.84E+00							1.48E+01	9.26E+01	
2-Methylnaphthalene	91-57-6	7.83E-06						1.07E-02	1.76E-04			1.71E-03	9.30E-05	4.53E-04	2.56E-03					
3-Methylchloranthrene	56-49-5	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
7,12-Dimethylbenz(a)anthracene	57-97-6	5.22E-06						7.11E-03	1.17E-04			1.14E-03	6.20E-05	3.02E-04	1.71E-03					
Acenaphthene	83-32-9	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Acenaphthylene	208-96-8	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Anthracene	120-12-7	7.83E-07						1.07E-03	1.76E-05			1.71E-04	9.30E-06	4.53E-05	2.56E-04					
Benz(a)anthracene	56-55-3	2.81E-05	4.68E-02	8.25E-03				8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Benzo(a)pyrene	50-32-8	3.91E-07						5.33E-04	8.80E-06			8.56E-05	4.65E-06	2.27E-05	1.28E-04					
Benzo(b)fluoranthene	205-99-2	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Benzo(g,h,i)perylene	191-24-2	3.91E-07						5.33E-04	8.80E-06			8.56E-05	4.65E-06	2.27E-05	1.28E-04					
Benzo(k)fluoranthene	207-08-9	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Chrysene	218-01-9	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Dibenzo(a,h)anthracene	53-70-3	3.91E-07						5.33E-04	8.80E-06			8.56E-05	4.65E-06	2.27E-05	1.28E-04					
Dichlorobenzene	106-46-7	3.91E-04						5.33E-01	8.80E-03			8.56E-02	4.65E-03	2.27E-02	1.28E-01					
Fluoranthene	206-44-0	9.78E-07						1.33E-03	2.20E-05			2.14E-04	1.16E-05	5.67E-05	3.20E-04					
Fluorene	86-73-7	9.13E-07						1.24E-03	2.05E-05			2.00E-04	1.08E-05	5.29E-05	2.98E-04					
Indeno(1,2,3-cd)pyrene	193-39-5	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Phenanathrene	85-01-8	5.54E-06						7.55E-03	1.25E-04			1.21E-03	6.59E-05	3.21E-04	1.81E-03					
Pyrene	129-00-0	1.63E-06						2.22E-03	3.67E-05			3.57E-04	1.94E-05	9.44E-05	5.33E-04					
Total Combined HAPs and TACs (tpy)		**181.47**	**81.44**	**14.37**	**0.00**	**0.00**	**0.00**	**0.93**	**0.01**	**0.02**	**0.00**	**0.07**	**0.00**	**0.02**	**0.10**	**4.17**	**59.17**	**0.01**	**0.05**	**2.11E+01**
Total HAPs* (tpy)		**15.94**	**2.46**	**0.44**	**0.00**	**0.00**	**0.00**	**0.42**	**0.01**	**0.00**	**0.00**	**0.07**	**0.00**	**0.02**	**0.10**	**4.17**	**0.00**	**0.00**	**0.00**	**8.25E+00**

Note:
* Denotes pollutants that are not listed as Federal HAPs. These pollutants are not included in the HAP total provided. As shown, combined annual HAP emissions are less than 25 tons per year. Additionally, individual HAP emissions are below 10 tons per year.
ASU = Air Separation Unit
CAS = Chemical Abstracts Service Registry Number
HAPs = hazardous air pollutant
lb/yr = pounds per year
TACs = toxic air contaminants

CO_2 vent hourly emissions were calculated based on maximum hourly flow (by mass) of the vent, and the concentration of TACs in the vent stream. The H_2S content in the vent stream is calculated based on a 10 ppm concentration in the vent gas, and the COS content is assumed to be 10 ppm. This CO_2 vent is used during start-up and emergency upset conditions, which are, by definition, unplanned and difficult to predict. Although the CO_2 centrifugal compressor and other injection equipment have historically been very reliable, as a worst-case scenario, annual emission rates were calculated based on 504 hours of full-rate venting per year.

The only emissions associated with the HP and LP Urea Absorbers are ammonia, which are reduced by the wet scrubber. The ammonia emission rate for each absorber was provided by the Project engineers. The Urea Absorbers will operate 8,052 hours per year.

The only TAC emitted by the Urea Pastillation Unit is ammonia. The ammonia emission rate was provided by the Project engineers. The Urea Pastillation Unit will operate 8,052 hours per year.

The HECA nitric acid plant will have an ammonia emission limit of 5 ppm due to slip from the SCR. Annual emissions are based on 8,052 hours of operation per year.

The two diesel generator hourly emission rates were calculated based on the horsepower rating of each generator, and the USEPA interim Tier 4 emission standard particulate emission rate. Annual emissions were calculated based on 50 hours per year of operation for each of two generators.

Fire-pump engine hourly emission rates were calculated based on the horsepower rating of the engine, and the USEPA interim Tier 4 emission standard particulate emission rate. Annual emissions were calculated based on 100 operating hours per year.

5.3.2 Fugitive Emissions

Fugitive emissions of TACs may occur in some areas of the facility due to leaks in the piping and components. Fugitive emissions are associated primarily with the gasification block and the Manufacturing Complex. An LDAR program will be implemented in select process areas to minimize these emissions. LDAR is the primary established method for controlling fugitive emissions from equipment, such as valves and seals.

The Applicant proposes to apply the LDAR program to the following areas in the Gasification Block: Area # 1(methanol), Area # 5 (propylene), Area # 7 (H_2S-laden methanol), Area #8 (CO_2-laden methanol), Area # 9 (acid gas), and Area # 10 (ammonia-laden gas), and all portions of the Manufacturing Complex. These areas were selected because they had the largest calculated uncontrolled emissions for methanol, propylene, H_2S, and ammonia.

The SJVAPCD released a memo "Procedures for Quantifying Fugitive VOC Emissions at Petroleum and Synthetic Organic Chemicals Manufacturing Industry (SOCMI) Facilities" (2005). The memo recommends using emission factors from the California Air Pollution Control Officers Association (CAPCOA) document "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities" (1999), or

the emission factors from the U.S. Environmental Protection Agency (USEPA) document "Protocol for Equipment Leak Emission Estimates" (1995a) for new or modified emission units. In cases where the CAPCOA and USEPA emission factors are different, the SJVAPCD memo says that CAPCOA emissions factors will take precedence over the USEPA emission factors. The USEPA guidance includes emission factors for SOCMI facilities, whereas the CAPCOA guidance does not.

According to the USEPA document (USEPA, 1995a), the criteria for determining the appropriateness of emission factors are based on the following: (1) process design; (2) process operation parameters; (3) types of equipment used; and (4) types of material handled. Based on these criteria, the Project processes are most similar to a SOCMI plant. Therefore, the SOCMI fugitive emission factors from USEPA are used in the fugitive emission calculations.

Although the fugitive emission factors are typically used for VOC emission, the USEPA document (USEPA, 1995a) states that the average emission factors can be used for inorganic compounds (like H_2S and ammonia), in the event that there is no other approach available to estimate the concentration of the inorganic compounds at the equipment leak source. Because this is a new facility, it is not possible to estimate the fugitive concentrations of the inorganic compounds at the equipment leaks; therefore, the average emission factor approach was used. The SOCMI fugitive emission factors were multiplied by the equipment component count, split by service types and the weight percentage of the compounds in the stream.

No gasification facilities similar to the HECA Project were identified that have prepared site-specific fugitive emissions factors. Therefore, the average emission factor approach (from USEPA) was used as the best estimate for fugitive emissions. Detailed emission calculations for the fugitives are presented in Appendix F, Toxic Air Contaminant Emissions.

5.3.3 Mobile Sources

For CEQA purposes, on-site mobile source diesel particulate matter (DPM) emissions were incorporated in the HRA. Trucks and trains delivering feedstock and removing products would travel to and from the Project Site on a regular basis.

DPM emissions (using PM_{10} emission factors) associated with the truck movement on the HECA site were calculated using heavy-heavy-duty diesel truck emission factors for all trucks except the Operations and Maintenance trucks, which were calculated with the light-heavy-duty diesel factors, from the CARB on-road emissions model EMFAC2007. The anticipated Project start date is 2017. HECA will use a fleet of delivery trucks that are model year 2010 or newer; thus, EMFAC2007 emissions factors for vehicles for calendar year 2010 were used in the emission calculations.

The emissions factors for PM_{10} for line-haul and switch locomotives were obtained from the USEPA document "Technical Highlights: Emission Factors for Locomotives" for Tier 3 engines. On-site feedstock and product train emissions were calculated assuming the majority of the time the line-haul engines will operate in Notch 1 or idling; therefore, emissions were conservatively estimated for Notch 1 horsepower. The percentage of total engine horsepower used at Notch 1 was obtained from the "Port Of Long Beach Air Emissions Inventory for 2007,"

which was based on data derived from the USEPA. Emissions from the switching engine were based on the USEPA Tier 3 emission factors and maximum switching engine horsepower of 260 hp.

5.3.4 Total Project Toxic Air Contaminant Emissions

Table 5-2 presents a summary of the total annual TAC emissions from all sources. Detailed hourly and annual emission calculations for each source are presented in Appendix F, Toxic Air Contaminant Emissions.

SJVAPCD Rule 2520 requires adherence to federally mandated operating permits. As such, it is important to designate whether the project is a major source of HAPs or not. Under the federal CAA, §112, a major source is defined as one that emits 10 tons per year or more of any HAP, or 25 tons per year or more of any combination of HAPs. The Project is not a major source of HAPs, as determined by the list of federal HAPs and the Project's total annual HAP emissions presented in Table 5-2.

5.4 MODEL INPUT PARAMETERS

The HRA was conducted using the hourly and annual emissions listed for each source identified in Table 5-2. Cancer and chronic non-cancer health effects were evaluated using the HARP model with estimated annual average emission rates, and acute non-cancer health effects were analyzed based on maximum hourly emission rates.

Dispersion modeling was performed using the AERMOD model and methods consistent with the approach described in Section 4 (e.g., building downwash and meteorological input data), and the modeling protocols submitted for review to USEPA, CEC, and SJVAPCD.

The AERMOD model is run with unit emission rates (1 gram per second emissions) for each source described above to calculate the concentration of TACs per unit emission rate from each source. HARP then uses this information, along with the estimated source emission rates for specific TAC compounds (as described above and in Appendix F, Toxic Air Contaminant Emissions, to calculate ground-level concentrations for each chemical species. All sources described in Section 5-3 are included in the modeling analysis and HRA.

Meteorological data for the years 2006 through 2010 (the same years used in the air quality modeling analysis described in Section 4) were used in the HRA. Risk values were modeled for the sensitive and residential receptors identified in Section 5.1, and at all grid receptors within 6 miles (10 kilometers) of the site. The same grid receptors used in the air quality modeling were used in the HRA. To be certain that the maximum potential risks resulting from Project emissions would be addressed, all receptors were treated as sensitive receptors.

The stack parameters used for the full-load operations of the CTG/HRSG with duct burning at the average ambient temperature of 65°F were used in the modeling. HECA anticipates that 1 to 2 plant start-ups/shut-downs will be necessary for maintenance annually. Due to the limited operation in start-up mode, only stack parameters for the CTG/HRSG for the on-peak average ambient temperature case were included in the modeling assessment.

Toxicological data, cancer potency factors, and RELs for specific chemicals are built into the CARB's HARP model. The pollutant-specific cancer potency factors and RELs used in the HRA are listed in Table 5-1. The HARP model uses the toxicological data in conjunction with the other input data described above to perform health risk estimates, based on OEHHA equations and algorithms.

5.5 CALCULATION OF HEALTH EFFECTS

Adverse health effects are expressed in terms of cancer or non-cancer health risks. Cancer risk is typically reported as "lifetime cancer risk," which is the estimated maximum increase in the risk of developing cancer caused by long-term exposure to a pollutant suspected of being a carcinogen. The calculation of cancer risk conservatively assumes an individual is exposed continuously to the maximum pollutant concentrations 24 hours per day for 70 years. Although such continuous lifetime exposure to maximum TAC levels is highly unlikely, the goal of the approach is to produce a conservative worst-case estimate of potential cancer risk.

Non-cancer risk is typically reported as a THI. The THI is calculated for each target organ as a fraction of the maximum acceptable exposure level or REL for an individual pollutant. The REL is generally the level at (or below) which no adverse health effects are expected. The THIs are calculated for both short-term (acute) and long-term (chronic) exposures to non-carcinogenic substances by adding the ratios of predicted concentrations to RELs for all pollutants.

Both cancer and non-cancer risk estimates produced by the HRA represent incremental risks (i.e., risks due to the modeled sources only) and do not include potential health risks posed by existing background concentrations. The HARP model performs all of the necessary calculations to estimate the potential lifetime cancer risk, and the acute and chronic non-cancer THIs due to the Project's TAC emissions. The acute 8-hour THI is calculated directly from the predicted concentrations of acetaldehyde, arsenic, formaldehyde, manganese, and mercury.

5.6 HEALTH EFFECTS SIGNIFICANCE CRITERIA

Various state and local agencies provide different significance criteria for cancer and non-cancer health effects. For the Project, the SJVAPCD *Guidelines for Assessing and Mitigating Air Quality Impacts* (January 2002) provide the significance criteria for potential cancer and non-cancer health effects due to Project-related emissions. For carcinogenic health effects, an exposure is considered significant when the predicted increase in lifetime cancer risk exceeds 10 in 1 million ($10 \times 10\text{-}^{6}$). For non-carcinogenic acute and chronic health effects, an exposure that affects each target organ is considered significant when the corresponding THI exceeds a value of 1.0.

5.7 ESTIMATED LIFETIME CANCER RISK AND CHRONIC AND ACUTE TOTAL HAZARD INDICES

Table 5-3, Estimated Cancer Risk, Acute and Chronic Non-Cancer THI due to HECA Operations, presents the results of the HRA at the point of maximum impact, maximally exposed individual resident (MEIR), MEIW, and nearest sensitive receptor.

Table 5-3
Estimated Cancer Risk, Acute and Chronic Non-Cancer THI due to HECA Operations

Location	Cancer Risk	Chronic Non-Cancer Total Hazard Index	Acute Non-Cancer Total Hazard Index
Point of maximum impact	8.97 excess risk in 1 million	0.42	0.88
Coordinates of PMI in UTM NAD83 (m) easting northing	283,967 3,911,925	283,959 3,911,625	282,663 3,912,844
Peak risk at off-site worker MEIW (Tule Elk State Reserve Ranger Station)	1.90 excess risk in 1 million	0.13	0.23
Coordinates of MEIW in UTM NAD83 (m) easting northing	285,106 3,911,707	285,106 3,911,707	285,106 3,911,707
Peak risk at MEIR	4.29 excess risk in 1 million	0.29	0.33
Coordinates of MEIR in UTM NAD83 (m) easting northing	283,989 3,910,951 (Residence along the southeastern side of the property line on Tupman Road)	283,989 3,910,951 (Residence along the southeastern side of the property line on Tupman Road)	284,401 3,912,477 (Residence on Tule Park Road near Station Road)
Peak risk at nearest Sensitive Receptor (Elk Hills School, Tupman, California)	0.96 excess risk in 1 million	0.07	0.11
Coordinates of Sensitive Receptor in UTM NAD83 (m) easting northing	285,878 3,908,605	285,878 3,908,605	285,878 3,908,605
Significance threshold	10 in 1 million	1	1
Below significance?	Yes	Yes	Yes

Source: HECA, 2012.
Notes:
1. MEIW cancer risk is conservatively based on a residential risk calculation; i.e., a 70 year exposure.
m = meters
MEIR = maximally exposed individual resident
MEIW = maximally exposed individual worker
PMI = point of maximum impact
THI = total hazard index
UTM = Universal Transverse Mercator

MEIR for the cancer and chronic and acute non-cancer health risks are presented in Table 5-3. As shown in this table, all health risks were predicted to be below the significance thresholds.

The AERMOD modeling files and risk calculation reports from HARP are included in the electronic files with this AFC Amendment. The files include calculated X/Q values in µg/m^3 per gram per second from each source at each receptor.

The maximum acute 8-hour THI resulting from worst-case hourly emissions of acetaldehyde, arsenic, formaldehyde, manganese, and mercury are presented in Table 5-4, Acute Hazard Index for TACs with 8-Hour RELs Predicted from Peak HECA Emissions, along with the summation of the health indices by target organ to obtain the 8-hour total hazard index per organ.

Table 5-4
Acute Hazard Index for TACs with 8-hour RELs Predicted from Peak HECA Emissions

TAC	8-hour Inhalation Risk Value µg/m^3	Hazard Index	Hazard Index Target Organs
Acetaldehyde	300	0.000005	Respiratory system
Arsenic	0.015	0.1267	Development; cardiovascular system; nervous system; lung; skin
Formaldehyde	9	0.0320	Respiratory system
Manganese	0.17	0.0097	Nervous system
Mercury	0.06	0.0187	Nervous system
Total Hazard Index – Respiratory system		**0.0320**	**Respiratory system**
Total Hazard Index - Nervous system		**0.1550**	**Nervous system**
Total Hazard Index – Other organs		**0.1267**	**Development; cardiovascular system; lung; skin**

Notes:
RELs = reference exposure levels
TACs = toxic air contaminants
µg/m^3 = micrograms per cubic meter

The estimated cancer risk at all locations is below the significance criterion of 10 in 1 million; thus, the Project emissions are expected to pose a less-than-significant increase in terms of carcinogenic health risk.

The estimated chronic and acute THIs are below the significance criterion of 1.0; thus, the Project emissions of noncarcinogenic TACs would not be expected to pose a significant risk.

5.8 UNCERTAINTY IN THE PUBLIC HEALTH IMPACT ASSESSMENT

Sources of uncertainty in the results of HRAs include emissions estimates, dispersion modeling, exposure characteristics, and extrapolation of toxicity data in animals to humans. For this reason, assumptions used in HRAs are typically designed to provide sufficient health protection

to avoid underestimation of risk to the public. Some sources of uncertainty applicable to this HRA are discussed below, along with the procedures and assumptions used to ensure health-protective results.

The turbine emission rates were derived from emission factors from a similar project, and using vendor data regarding ammonia slip and mercury rates. Both the short- and long-term turbine emissions estimates were developed assuming that the turbine will operate continuously, and at the maximum fuel energy input rate. Under actual operating conditions, the turbine will typically operate fewer hours per year and at lower loads. Consequently, the emissions used for this HRA are likely to be higher than what would be experienced under power plant operation.

Dispersion models approved for regulatory applications contain assumptions that lead to over-prediction of ground-level concentrations. For example, the modeling performed in the HRA assumed a conservation of mass (i.e., all of the pollutants emitted from the sources remained in the atmosphere while being transported downwind). During the transport of pollutants from sources toward receptors, none of the emitted material was assumed to be removed from the source plumes by means of chemical reactions or losses at the ground surface due to reactions, gravitational settling, or turbulent impaction. In reality, these mechanisms work to reduce the level of pollutants remaining in the atmosphere during plume travel.

The exposure characteristics assessed in the HRA included the assumption that residents will be exposed to turbine emissions continuously at the same location for 24 hours per day, for 70 years. It is extremely unlikely that any resident will actually experience such exposure to the maximum predicted concentrations of TACs over this period. The conservative exposure assumption leads to over-predicted risk estimates in the HRA modeling.

The toxicity data used in the HRA contain uncertainties due to the extrapolation of health effects data from animals to humans. Typically, safety factors are applied when doing the extrapolation. Furthermore, the human population is much more diverse, both genetically and culturally, than bred experimental animals. The intraspecies variability is expected to be much greater among humans than in laboratory animals. With all of the uncertainty in the assumptions used to extrapolate toxicity data, significant measures are taken to ensure that sufficient health protection is built into the available health effects data.

Conservative measures to compensate for all of these uncertainties and ensure that potential health risks are not underestimated are compounded in the final HRA predictions. Therefore, the actual risk numbers are expected to be well below the values presented in this analysis.

5.9 MITIGATION MEASURES

The criteria pollutant emissions from the Project will be mitigated by the use of BACT and through emissions offsets. These measures are described in Section 3-2. Pollution control technologies employed to control criteria pollutants (for example, the oxidation catalyst in the HRSG and the high-efficiency drift eliminators on the cooling towers) will also reduce emissions of TACs associated with the Project. These measures satisfy the SJVAPCD requirements for toxics. Emissions from the cooling system will be limited by the use of high-efficiency drift

control eliminators, and a biocide will be used to control bacterial growth and thereby minimize the possibility of Legionella being transmitted from the cooling system.

The HRA presented in the foregoing subsections shows that the health effects impacts of the Project will be well below the significance thresholds identified in Section 5.6, Health Effects Significance Criteria. Therefore, no further mitigation of emissions from the Project is required to protect public health.

6.1 CLASS I AREA SIL ANALYSIS

Per USEPA Region IX request, a Class I Area SIL modeling analysis was completed to demonstrate compliance with the Class I SILs. Class I Areas are certain national parks, wilderness areas, and national monuments that are protected by the most stringent PSD requirements. The nearest Class I Area to the Project site is the San Rafael Wilderness Area, which is approximately 60 kilometers southwest of HECA.

Modeling was conducted for the NO_2 annual, $PM_{2.5}$ 24-hour and annual, and PM_{10} 24-hour and annual Class I SILs. The Class I SILs are presented in Table 6-1. Modeling for the Class I $PM_{2.5}$ SILs was completed, because the San Rafael Wilderness Area is in Santa Barbara County, which is an unclassified/attainment area for $PM_{2.5}$. Class I SILs for NO_2 1-hour, and CO 1-hour, and 8-hour do not exist. Impacts due to HECA operations without mobile sources were modeled, using the same modeling scenarios as described in Section 4.1.9.2. The AERMOD model was applied for the Class I SIL modeling analyses, which used a receptor grid extending out 50 kilometers from the Project site, the same receptor grid used in the NO_2 1-hour NAAQS regional analysis (Appendix I, NO_2 1-Hour Regional Analysis). The AERMOD model has been evaluated for estimating impacts out to 50 kilometers, and it is believed that this is the maximum extent of the model's reliability; therefore, receptors did not extend beyond 50 kilometer into the San Rafael Wilderness Area. However, this modeling approach, with receptors out to 50 kilometers, gave an understanding of whether the model predicted Class I SILs would be contained inside the 50-kilometer grid. Isopleth figures were prepared for each pollutant and averaging time to show the extent of the areas with Project Impacts above the SILs.

Table 6-1
Class I Significant Impact Levels

Pollutant	Averaging Period	Class I Significant Impact Level (SIL) [1] ($\mu g/m^3$)
NO_2	Annual	0.1
PM_{10}	24 hour	0.32
	Annual	0.2
$PM_{2.5}$	24 hour	0.07
	Annual	0.06

Notes:
[1] The SIL concentrations in this table were compared to highest modeled concentrations from HECA stationary sources for NO_2, PM_{10} and $PM_{2.5}$ annual, and PM_{10} 24-hour. For $PM_{2.5}$ 24-hour the model was run to predict the multiyear average of the highest 24-hour concentration at each receptor.

Figures 6-1 through 6-5 provide a visualization of the model predicted concentration isopleths for each pollutant and averaging time. The red isopleth line plotted in each figure represents the pollutants' Class I SIL level. Additional isopleths (in orange) are included on the 24-hour figures to show the extent of higher predicted concentrations. The figures illustrate that for all pollutants and averaging times the Class I SIL isopleths do not come close to the San Rafael Wilderness Area Class I Area. The model predicted that the NO_2, PM_{10}, and $PM_{2.5}$ annual concentrations fall below

the Class I SILs within 2 to 3 kilometers, as shown on Figures 6-1 through 6-3. For the PM_{10} and $PM_{2.5}$ 24-hour averaging times, the model predicted that the concentrations would fall below the Class I SIL out 20 to 30 kilometers southwest of HECA, in the direction toward San Rafael Wilderness Area, as shown on Figures 6-4 and 6-5. Therefore, modeled concentrations due to HECA operations in the vicinity of San Rafael Wilderness are well below the Class I significance levels; therefore, compliance with the Class I SILs is achieved. Because the SILs are not exceeded in the Class I Area, a Class I Area increment analysis is not required.

6.2 AIR QUALITY RELATED VALUES

6.2.1 Class I Areas

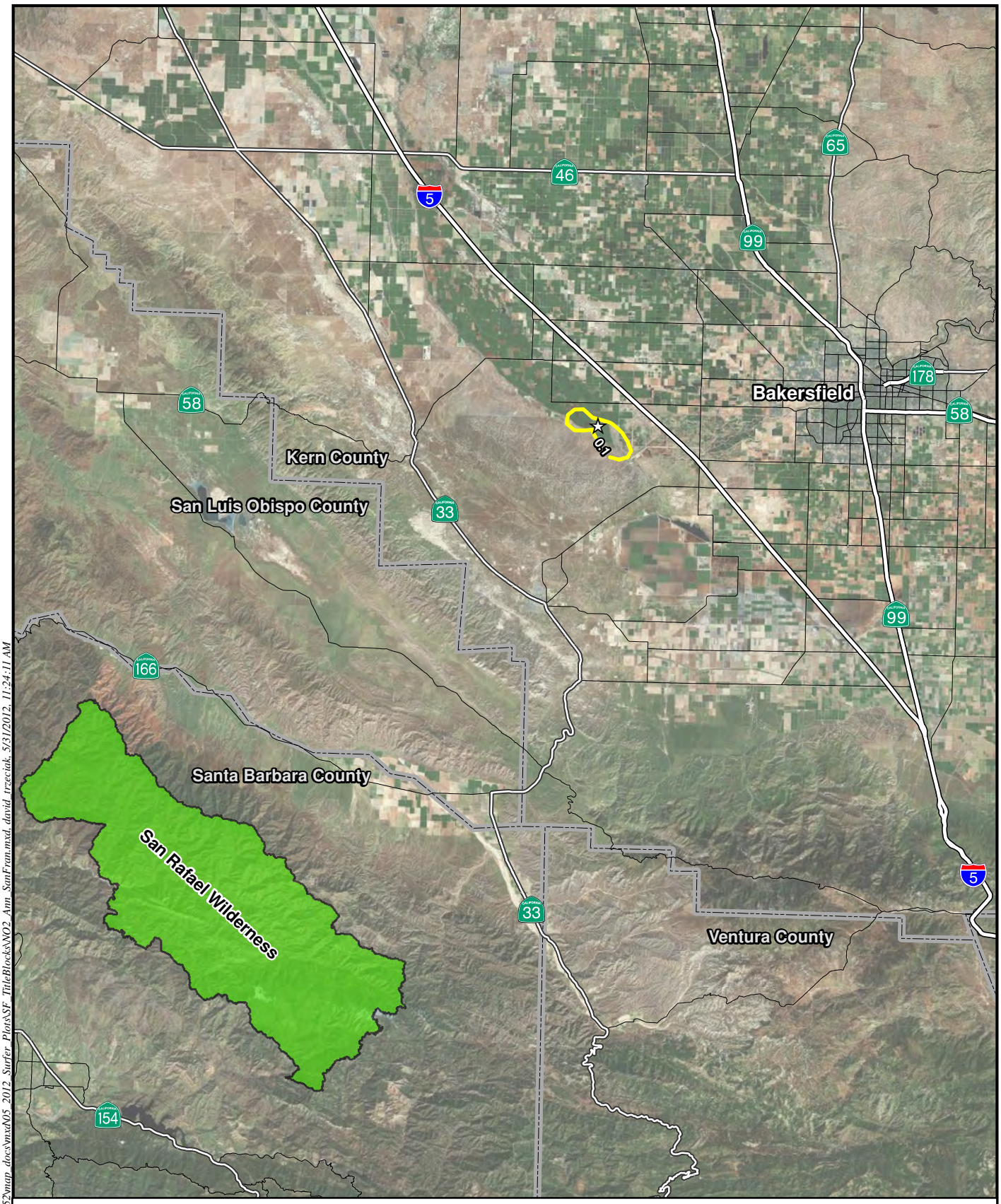
The nearest Class I Area to the HECA Project is San Rafael Wilderness Area, approximately 60 kilometers away. The next nearest Class I Areas are Domelands Wilderness Area— about 105 kilometers away—and Sequoia National Park, 120 kilometers away. As identified in the February 2012 HECA modeling protocol supplement, the Federal Land Managers' AQRV Work Group (FLAG) guidance from 2010, FLAG provides a method to determine if projects greater than 50 kilometers from a Class I Area need to conduct analyses in the Class I Area (NPS, 2010). This screening method is based on the sum of the annualized daily emissions of PM_{10}, NO_2, SO_2, and H_2SO_4 divided by the distance to the nearest Class I Area (Q/d). The Q/d value for the HECA Project for the San Rafael Wilderness Area is less than 5, which is less than the screening threshold of 10; therefore, HECA did not prepare Class I Area AQRV analyses for this Application. Q/d values for the Domelands Wilderness Area and Sequoia National Park Class I Areas are less than 3. On April 18, 2012, the U.S. Forest Service confirmed that a revised AQRV analysis would not be required for the HECA Project.

It should be noted that in the previous PSD application, HECA prepared Class I Area AQRV analyses for the San Rafael Wilderness Area, all of which showed less-than-significant impacts. The emissions of the revised HECA Project have decreased or remained similar to previous levels; thus, HECA impacts should decrease or remain similar, and impacts from the HECA Project in Class I Areas would remain less than significant.

6.2.2 Class II Areas

National Park Service (NPS) PSD guidance states that projects should not degrade air quality and/or visibility in Class II areas. Class II areas are defined as the following areas when greater than 10,000 acres, and in existence since 1977:

- National monuments;
- National primitive areas;
- National preserves;
- National recreation areas;
- National wild and scenic rivers;
- National wildlife refuges;
- National lakeshores and seashores; and
- National parks and wilderness areas.



Project Site

Class I SIL NO_2 Annual 0.1 µg/m^3

County Boundary

San Rafael Wilderness Area

N

0 5 10 Kilometers

SOURCES:
Contours (URS, 2012), San Rafael Wilderness (USFS, 2009)
County Boundary, Streets (ESRI, 2007), Aerial (Bing Maps, 2012)

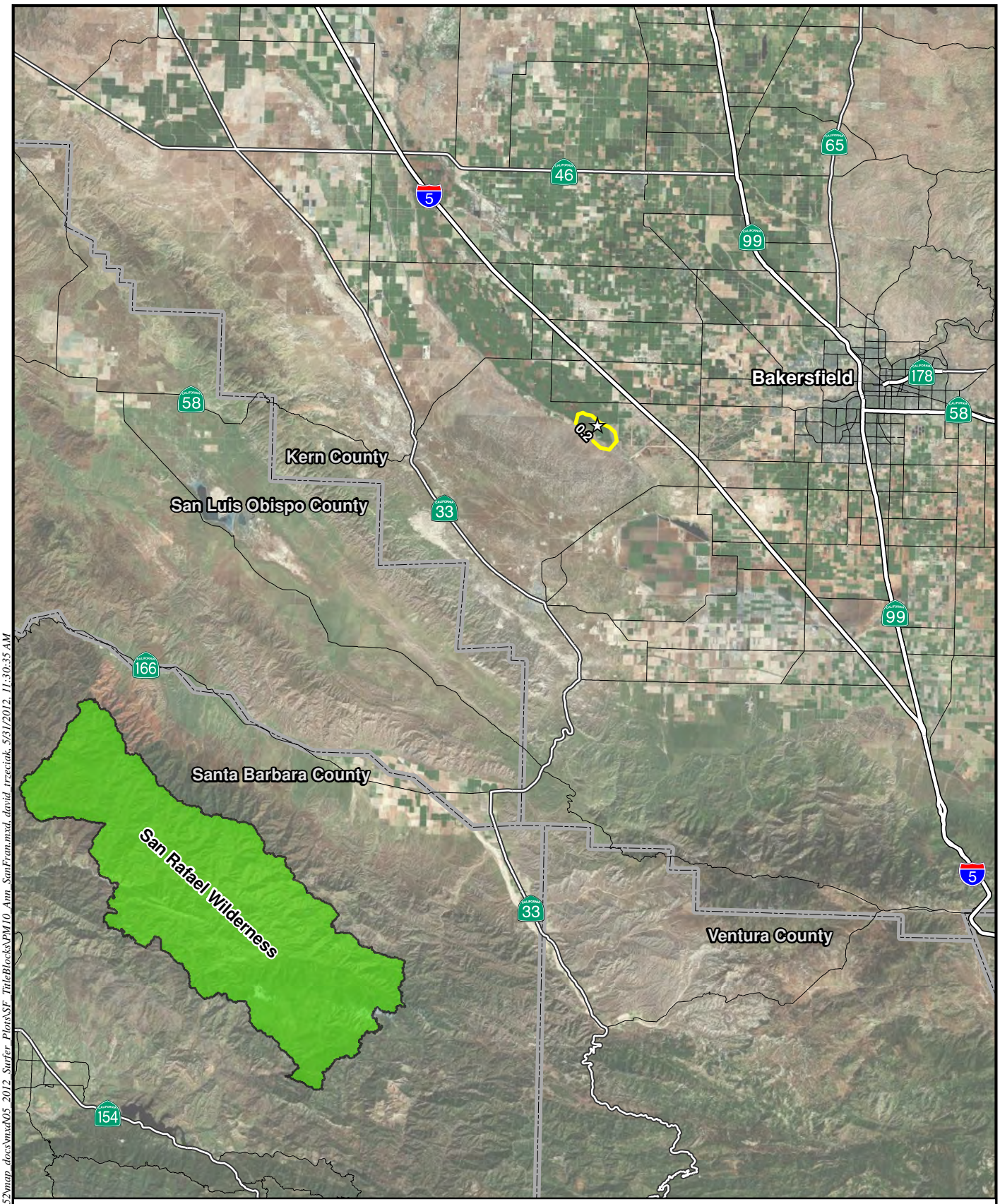
EXTENT OF NO_2 ANNUAL CLASS I SIL FROM HECA OPERATIONS

May 2012 Hydrogen Energy California (HECA)
28068052 Kern County, California

URS

FIGURE 6-1

Path: G:\etsyprojects\1577\28068052\map_docs\mxd\05_2012_Surfer_Plots\SF_TitleBlocks\NO2_Ann_SanFran.mxd, david_trzeciak, 5/31/2012, 11:24:11 AM



☆ Project Site

Class I SIL PM_{10} Annual 0.20 µg/m^3

County Boundary

San Rafael Wilderness Area

N

0 5 10 Kilometers

SOURCES:
Contours (URS, 2012), San Rafael Wilderness (USFS, 2009)
County Boundary, Streets (ESRI, 2007), Aerial (Bing Maps, 2012)

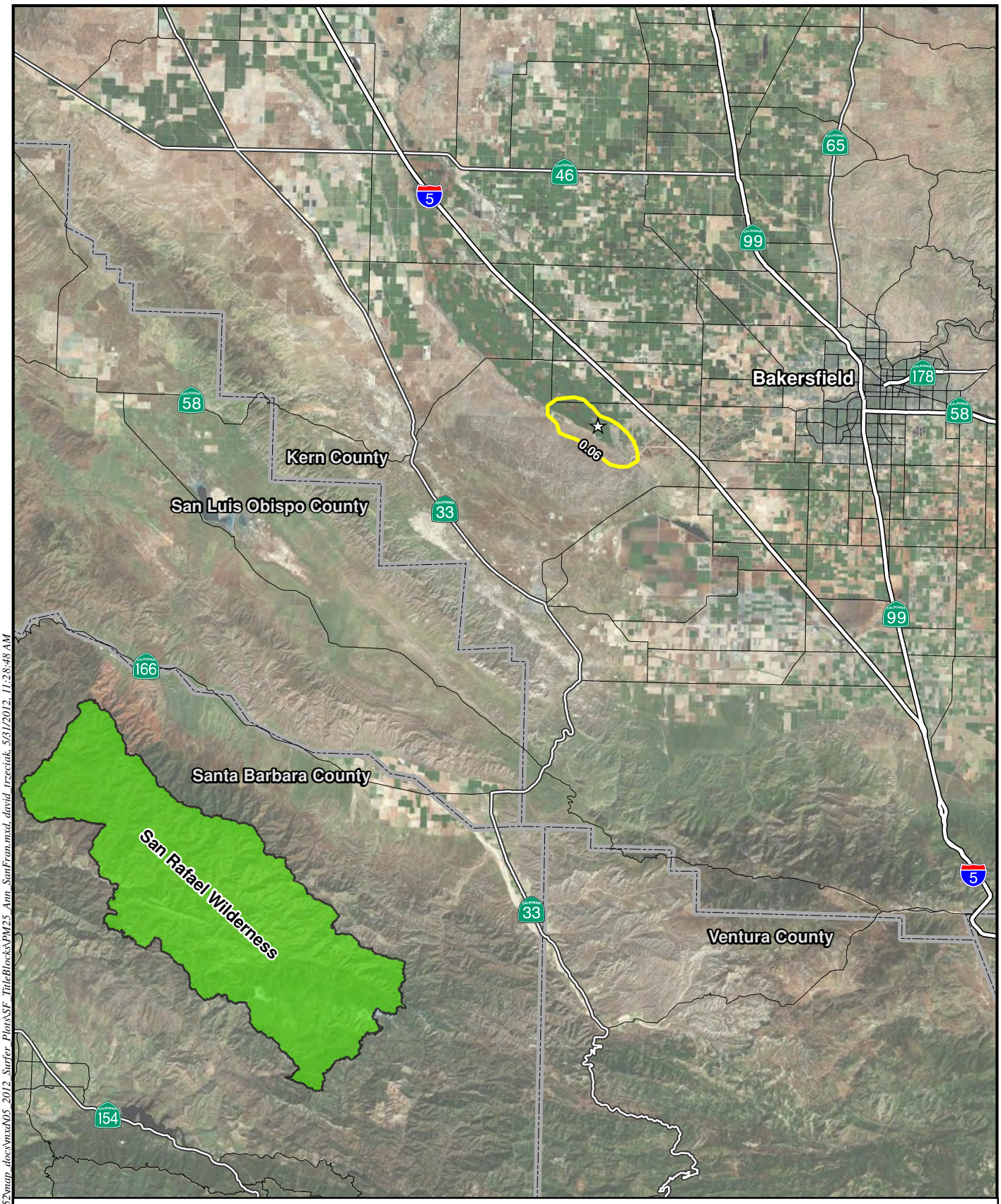
EXTENT OF PM_{10} ANNUAL CLASS I SIL FROM HECA OPERATIONS

May 2012 Hydrogen Energy California (HECA)
28068052 Kern County, California

URS

FIGURE 6-2

Path: G:\gis\projects\1577\28068052\map_docs\mxd\05_2012_Surfer_Plots\SF_TitleBlocks\PM10_Ann_SanFran.mxd, david_trzeciak, 5/31/2012, 11:30:35 AM



Project Site

Class I SIL $PM_{2.5}$ Annual 0.06 µg/m^3

County Boundary

San Rafael Wilderness Area

N

0 5 10 Kilometers

SOURCES:
Contours (URS, 2012), San Rafael Wilderness (USFS, 2009)
County Boundary, Streets (ESRI, 2007), Aerial (Bing Maps, 2012)

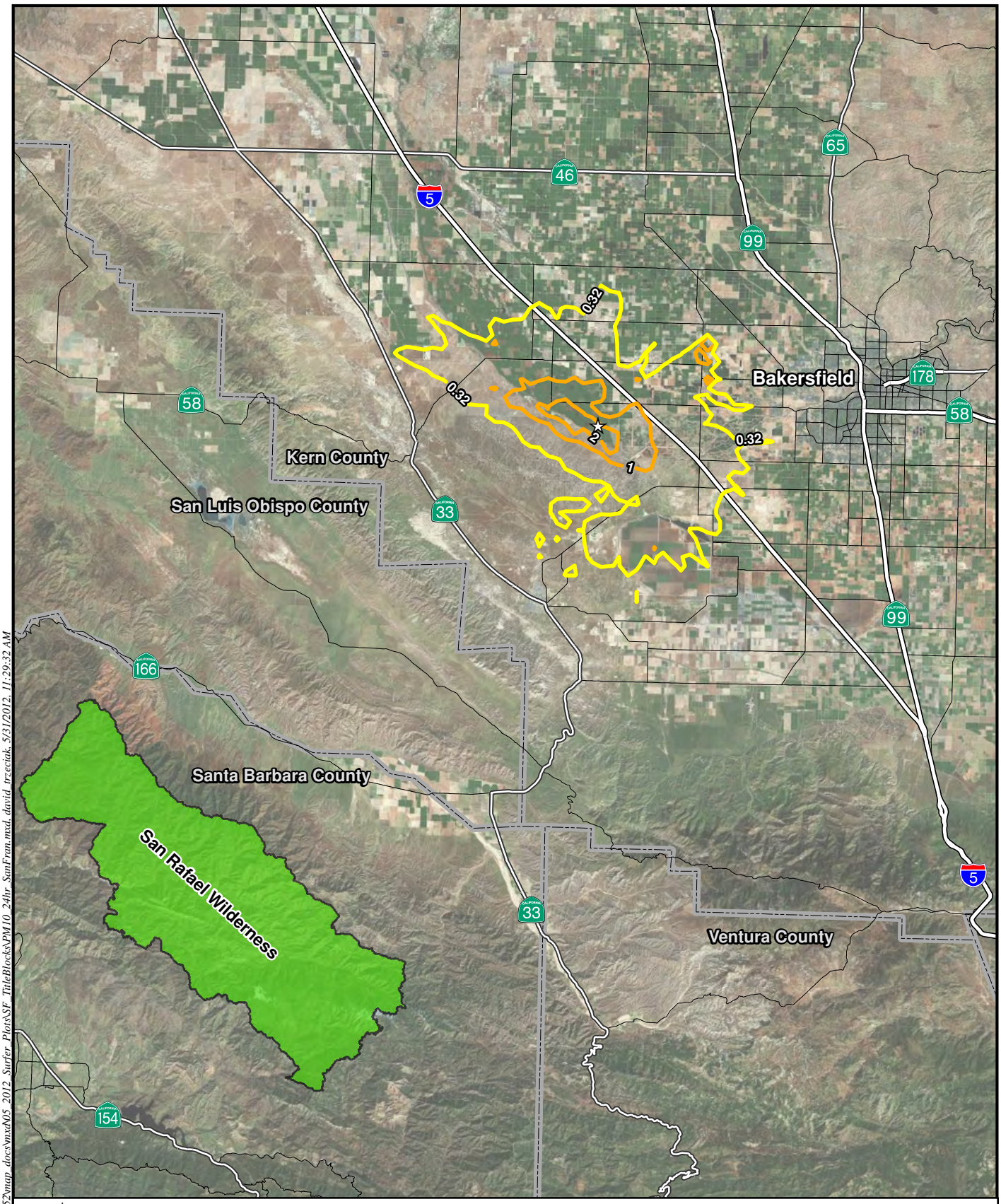
EXTENT OF $PM_{2.5}$ ANNUAL CLASS I SIL FROM HECA OPERATIONS

May 2012 Hydrogen Energy California (HECA)
28068052 Kern County, California

URS

FIGURE 6-3

Path: G:\sites\projects\1577\28068052\map_docs\mxd\05_2012_Surfer_Plots\SF_TitleBlocks\PM25_Ann_SanFran.mxd, david_trzeciak, 5/31/2012, 11:28:48 AM



Project Site

Class I SIL PM_{10} 24-hour 0.32 $\mu g/m^3$

PM_{10} 24-hour Concentration Isopleths ($\mu g/m^3$)

County Boundary

San Rafael Wilderness Area

SOURCES:
Contours (URS, 2012), San Rafael Wilderness (USFS, 2009),
County Boundary, Streets (ESRI, 2007), Aerial (Bing Maps, 2012)

N

0 5 10 Kilometers

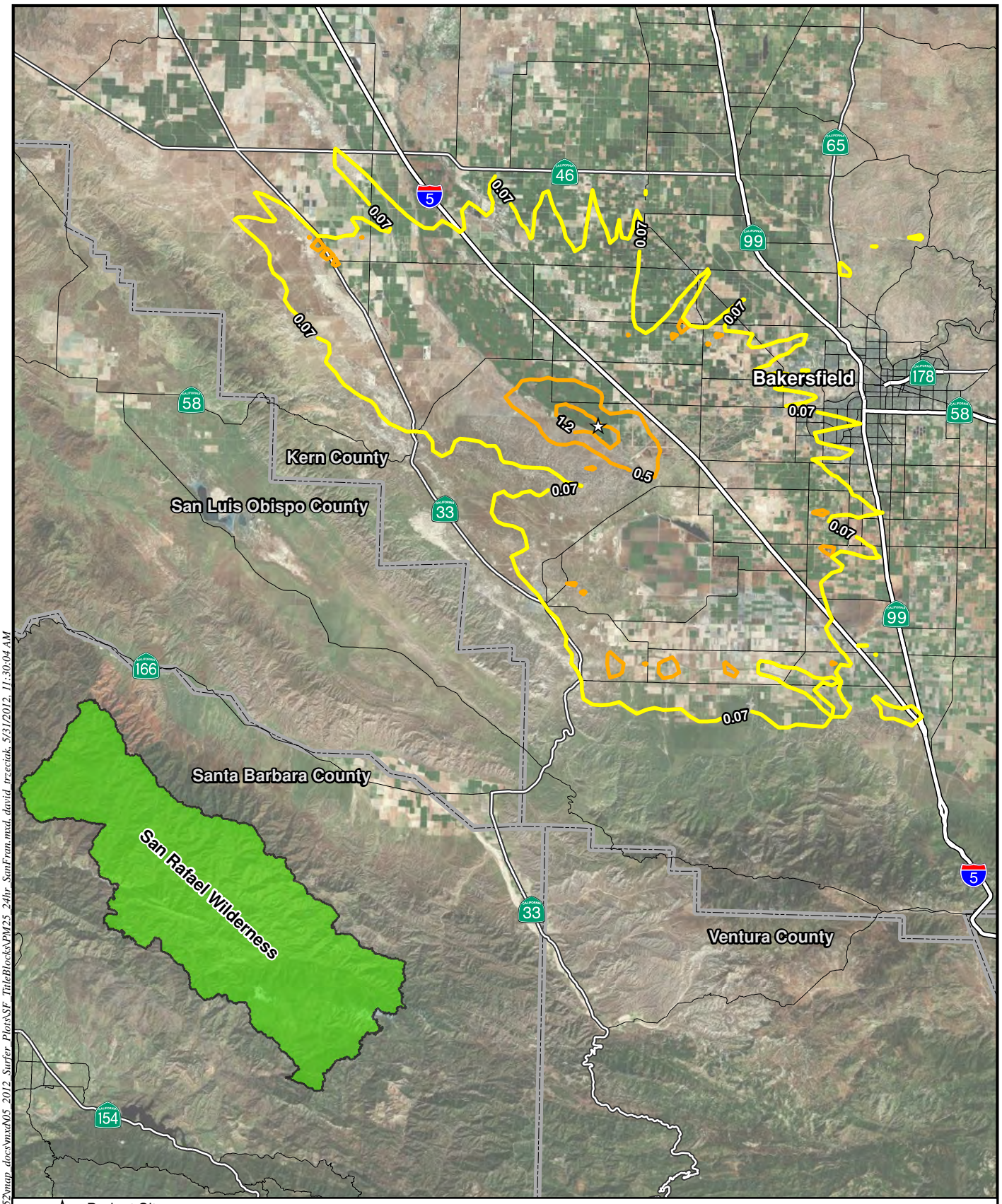
EXTENT OF PM_{10} 24-HOUR CLASS I SIL FROM HECA OPERATIONS

May 2012 Hydrogen Energy California (HECA)
28068052 Kern County, California

URS

FIGURE 6-4

Path: G:\gis\projects\1577\28068052\map_docs\mxd\05_2012_Surfer_Plots\SF_TitleBlocks\PM10_24hr_SanFran.mxd, david_trzeciak, 5/31/2012, 11:29:32 AM



Project Site

Class I SIL $PM_{2.5}$ 24-hour 0.07 µg/m^3

$PM_{2.5}$ 24-hour Concentration Isopleths (µg/m^3)

County Boundary

San Rafael Wilderness Area

N

0 5 10 Kilometers

SOURCES:
Contours (URS, 2012), San Rafael Wilderness (USFS, 2009)
County Boundary, Streets (ESRI, 2007), Aerial (Bing Maps, 2012)

EXTENT OF $PM_{2.5}$ 24-HOUR CLASS I SIL FROM HECA OPERATIONS

May 2012 Hydrogen Energy California (HECA)
28068052 Kern County, California

URS

FIGURE 6-5

Path: G:\sites\projects\1577\28068052\map_docs\mxd\05_2012_Surfer_Plots\SF_TitleBlocks\PM25_24hr_SanFran.mxd, david_trzeciak, 5/31/2012, 11:30:04 AM

The nearest parks that fit the Class II area definition are Sequoia National Forest, 54 kilometers away, and Los Padres National Forest, 49 kilometers away from HECA. Since both of these parks are approximately 50 kilometers or farther from HECA, and the Q/d is less than 6, per the FLAG guidance screening technique, impacts would be less than significant. Therefore, no Class II Area visibility analysis was conducted.

6.3 SOILS AND VEGETATION ANALYSES

The prevalent soil in the HECA Project area is the Lokern-Buttonwillow map unit, and the soil map units surrounding the HECA Project area are Cajon-Westhaven, Elkhills, Garces-Panoche, Kimberlina-Wasco, and Milham units. These soil map units are characterized as follows:

1. The Lokern-Buttonwillow map unit is a deep, nearly level, somewhat poorly drained clay. This map unit is used for native and irrigated pasture, irrigated crops, wildlife habitat, and some urban development. The saline-alkali condition of the soils, restricted permeability, and fine texture are the main limitations.

2. The Mercey-Kettleman-Elkhills-Delgado-Cantua-Bitterwater map unit is dominated in this area by the Elkhills map unit, which is a deep, rolling-to-steep, well-drained soil that formed in mixed, stratified alluvium. Most areas of this unit are used as rangeland. Oil wells are common on the unit. Steepness of slope and a hazard of erosion are the main limitations.

3. The Garces-Panoche map unit is a deep, nearly level, saline-alkali, well-drained silt loam and clay loam. This unit is mainly used for irrigated crops and pasture. The saline-alkali condition of the soils and very slow permeability are the main limitations.

4. The Cajon-Westhaven-Lerdo-Excelsior map unit is a deep, nearly level and gently sloping, well-drained and somewhat excessively drained loamy sand and fine sandy loam, found on flood plains and alluvial fans.

5. Milham is deep, nearly level, well-drained sandy loam. This unit is mainly used for irrigated crops (USDA, 2009).

In general, soils are mainly affected through the leaching of particulate contaminants and through the removal of gases by precipitation, followed by surface deposition. The adsorption rate is dependent on the distance from the source, the concentration of pollutant, soil properties, hydrological situations, and meteorological conditions. The dominant soil type in the vicinity of the HECA Project, the Lokern-Buttonwillow map unit, is expected to exhibit a relatively low sorption capacity, as demonstrated by generally slow permeability, for the PSD significant emission rate increases in CO, NO_X, and PM_{10} emissions associated with the Project. Other soils surrounding this area are well-drained and may have a higher sorption capacity. The PSD modeling concentration results are below the NAAQS (because the concentration is in compliance with the significance level) that are designed to protect health and welfare from any known or anticipated adverse pollutant impacts. Therefore, the soils in the area of the Project should not be adversely affected as a result of the Project.

The predominant food crops grown in Kern County based on commodity value are grapes, almonds, pistachios, and citrus. The surrounding area also supports alfalfa production. Acreage yields in 2010 were 11.61 tons per acre of grapes; 1.31 tons per acre of almonds; 2.32 tons per acre of pistachios; and 13.28 tons per acre of citrus (Kern County, 2011).

The direct effects of NO_X on vegetation are usually associated with and confined to areas near specific industrial sources, but there is little published information regarding vegetation injury in the field due to NO or other NO_X compounds (USEPA, 1982). Many reports, however, have substantiated NO_X effects on vegetation grown in laboratory conditions. *In vivo* experiments performed by Hill and Bennet (1970) showed that both NO and NO_2 inhibit apparent photosynthesis of oat (*Avena sativa*) and alfalfa (*Medicago sativa*) plants at concentrations below those that caused visible foliar injury. They found the threshold for this inhibition was 740 $\mu g/m^3$ for NO and 1,130 $\mu g/m^3$ for NO_2 in 90-minute fumigations. Other researchers have found a reduction in the photosynthetic rate of tomato (*Lycopersicon esculentum*) exposed to 470 $\mu g/m^3$ NO_2 and 310 $\mu g/m^3$ NO. The effect of the two gases in combination had an additive inhibitive effect on photosynthesis. For comparison, the maximum 1-hour modeled impact (including background) for the Project is 325 $\mu g/m^3$.

Czeh and Nothdruft (1951) fumigated a wide range of agricultural and horticultural crops with NO_2 in the laboratory and small greenhouses. Rape (*Brassica rapus*), wheat (*Triticum aestivum*), oats (*Avena sativa*), peas (*Pisum sp.*), potatoes (*Solanum tuberosum*), and beans (*Phaseolus vulgaris*) showed little or no injury from 564 $\mu g/m^3$ NO_2 for 1 hour of exposure. Taylor and Cardiff (cited in Taylor et al., 1975) exposed field crops to NO_2 in sunlight chambers. Several field crops exposed to 18,880 $\mu g/m^3$ NO_2 for 90 minutes showed little or no injury, but in tomato, a 90-minute exposure to 28,200 $\mu g/m^3$ increased the extent of injury by 90 percent. The authors concluded that the injury threshold for several field crops would be 18,800 to 28,200 $\mu g/m^3$ NO_2 for 90-minute exposures.

The effect of NO_X on several eastern forest tree species has been documented by Kress (1982). Two of the seven tree species he exposed—Virginia pine (*Pinus virginiana*) and Loblolly pine (*Pinus taeda*)—exhibited significant height growth effects in response to NO_2 administered at 191 $\mu g/m^3$ for 6 hours per day on 28 consecutive days.

Visible injury to plants is not reported for NO_X concentrations of 0.20 ppm (376 $\mu g/m^3$) or less, with only rare exceptions in cases with cumulative exposure times greater than 100 hours (USEPA, 2008). The maximum modeled concentration from the Project is in compliance with the annual NO_2 CAAQS of 57 $\mu g/m^3$; therefore, no detrimental effects on vegetation in the Project area will likely result from Project NO_X emissions.

There are very few data on the effects of sulfur compounds on mature trees or other native plants (USDA, 1992). Data on tree seedlings (Hogsett et al., 1989, cited in USDA, 1992) indicated that 24-hour average SO_2 concentrations below 20 parts per billion (ppb) (52.29 $\mu g/m^3$) do not produce visible injury symptoms. According to *Guidelines for Evaluating Air Pollution Impacts on Class I Wilderness Areas in California* (USDA, 1992), maximum SO_2 concentrations should not exceed 40 to 50 ppb (104.6 $\mu g/m^3$ to 130.7 $\mu g/m^3$) (24-hour mean), and annual average SO_2 concentrations should not exceed 8 to 12 ppb (20.9 $\mu g/m^3$ to 31.4 $\mu g/m^3$) in order to maximize protection of all plant species. According to the USEPA, there is no clear evidence of damage to

vegetation at levels below the current secondary SO_2 standard (USEPA, 2008). The SO_2 PSD modeling concentration results are below the NAAQS, CAAQS, and these concentrations; therefore, the vegetation in the surrounding area should not be adversely affected by the minor SO_2 emission increase occurring with the Project.

PM_{10} emissions can harm vegetation either directly through deposition on leaves or indirectly by causing changes to soil chemistry or the amount of radiation reaching the surface (USEPA, 2009b). The effects of PM on vegetation are highly dependent on the chemical composition of the constituent particles, which can vary from organics to acids and heavy metals. The PM_{10} impacts from the Project are in compliance with the NAAQS; secondary standards are designed to protect public welfare, including vegetation. Thus, the PM_{10} emissions are not considered a dangerous threat to the local vegetation.

Little is known regarding the effects of CO on vegetation, but some response may occur at levels approaching 1,000 ppm (1,150,000 $\mu g/m^3$) for a week or more. The maximum 1-hour CO concentration resulting from the Project is predicted to be well below this level; therefore, no significant impact on local vegetation from the CO emission increase is expected.

USEPA has established a screening procedure for determining impacts to plants, soils, and animals (USEPA, 1980). Table 5.3 of this USEPA guidance document lists screening concentrations for different pollutants that represent the lowest levels at which adverse effects to vegetation or soils may occur.

A comparison of the maximum concentrations predicted due to the HECA Project, and the screening concentrations listed in the USEPA document, are shown in Table 6-2. The maximum concentrations predicted to result from the HECA Project were calculated by summing the maximum modeled impact due to HECA emissions with the maximum background concentration for each pollutant and averaging time.

The maximum predicted 1-hour average NO_2 concentration, including background, was conservatively compared to the USEPA AQRV screening concentrations for the 4-hour, 8-hour, and weekly averaging periods. Likewise, the maximum predicted 8-hour average CO concentration, including background, was compared to the screening concentration for a 1-week averaging period, and the maximum predicted 1-hour H_2S concentration was compared to the 4-hour screening concentration. As demonstrated in the following table, this conservative comparison shows that maximum Project-related predicted NO_2, CO, SO_2, and H_2S concentrations are below the USEPA screening concentrations, and thus below the levels at which adverse effects to vegetation or soils are expected to occur.

Total concentrations of all pollutants for all averaging times are less than the AQRV threshold levels at which scientific studies have shown a potential for negative impacts on soils and vegetation. Therefore, pollutant emissions from the HECA Project are not expected to have adverse soils and vegetative impacts.

Table 6-2
Comparison of Maximum HECA Concentrations and USEPA Screening Concentrations

Pollutant	Modeled Averaging Time	Predicted Concentration[1] ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration($\mu g/m^3$)	USEPA AQRV Screening Concentration ($\mu g/m^3$)	USEPA AQRV Screening Averaging Time
SO_2	1-Hour	50	42	92	917	1-Hour
	3-Hour	29	26	55	786	3-Hour
	Annual	0.1	13	13.1	18	Annual
NO_2	1-Hour	185	140	325	3,760	4 and 8-Hour
					564	Weekly
	Annual	1.5	26	27.5	94	Annual
PM_{10}[2]	24-Hour	4.9	264	268.9	N/A	N/A
	Annual	0.8	54	54.8	N/A	N/A
CO	8-Hour	371	2485	2856	1,800,000	Weekly
H_2S	1-Hour	23	N/A	23	28,000	4-Hour

Notes:
AQRV = air quality related value
CO = carbon monoxide
H_2S = hydrogen sulfide
$\mu g/m^3$ = micrograms per cubic meter
NO_2 = nitrogen dioxide
PM_{10} = particulate matter of 10 microns or smaller
SO_2 = sulfur dioxide
VOC = volatile organic compound

6.4 GROWTH-INDUCED IMPACTS

There are no changes to the land uses or zoning designations surrounding the area of the Project Site. The existing character of the immediate area surrounding the Project Site will remain unchanged by the development of the Project. Construction of the Project would last approximately 49 months and require approximately 2,500 employees during the peak construction period. This influx of workers and emissions associated with construction activities is temporary and will not contribute to associated growth in the region.

The Project will require 200 full-time employees working at the HECA facility during operation. It is anticipated that approximately 60 percent of operations employees will originate from the Kern County labor force. The remaining employees will originate from outside Kern County. Of the 40 percent non-local workers (80 workers), it is assumed for the purposes of this analysis that half (40 employees) will relocate to Kern County. Based on U.S. Census data for 2010, the population of Kern County is 839,631; therefore, the Project will not cause any significant population increases or associated growth (U.S. Census Bureau, 2012). The other half (40 employees) will commute on a daily or weekly basis. The Project's impacts with regard to land use planning and public policy will be minimal. The Project is consistent with the

development standards for the Exclusive Agriculture zoning district. The use of the 453-acre Project Site will change from agricultural use to power generation and manufacturing of low-nitrogen-based products.

SJVAPCD Rule 2201 requires a project with operational emissions of nonattainment pollutants and precursors above specific thresholds to provide offsets as mitigation for net emissions increases resulting from the Project, unless otherwise exempt from the offset requirement. Applicable thresholds are 10 tpy of NO_X or VOC, 100 tpy of CO, 14.6 tpy of PM_{10}, 100 tpy of $PM_{2.5}$, and 27.375 tpy of SO_X. In the case of the Project, offsets will not be required for CO per Section 4.6.1 of SJVAPCD Rule 2201, "Emission Offsets shall not be required for the following: Increases in CO in attainment areas if the applicant demonstrates to the satisfaction of the Air Pollution Control Officer (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." Modeling results presented in Section 5, Modeling Analysis provide this demonstration for CO. Thus, CO offsets are not proposed.

HECA emissions of $PM_{2.5}$ are less than the SJVAPCD offset threshold; therefore, ERCs are not required for $PM_{2.5}$.

To demonstrate compliance with SJVAPCD rules, the Project is required to provide emission offsets in the form of ERCs equal to increases in gross emissions of NO_X, SO_X, PM_{10}, and VOCs that will result from the operation of the Project, minus the specified thresholds. As discussed below, the Project proposes to further mitigate emissions of these pollutants beyond applicable offset requirements by offsetting the full amount of the Project net emission increase.

SJVAPCD Rule 2201 Section 4.8 specifies distance ratios that must be applied in determining the quantity of ERCs to be provided for a new source. If the location of the offsetting emission reduction is less than 15 miles from the new source, the ratio for a major source is 1.3 to 1. If the location of the offsetting emission reduction is 15 miles or more from the new source, the applicable offset ratio is 1.5 to 1. In the case of the Project, the VOC ERCs procured resulted from an emission reduction that occurred less than 15 miles from the Project Site, and a factor of 1.3 was applied. For all other pollutants for which offsets are required, the location of the emission reduction resulting in the ERC is greater than 15 miles from the Project Site, and a factor of 1.5 was applied.

The Project will use SO_X ERCs to offset PM_{10} emissions on an inter-pollutant basis. The SJVAPCD has developed an inter-pollutant trading ratio for SO_X to PM_{10} of 1:1 and concluded that this is protective of managing regional particulate matter impacts and progress towards attainment.

Based on operational emissions data presented in Section 4.4, and applying the appropriate ratios, the calculation of offsets is presented in Table 7-1. HECA has procured sufficient ERCs to satisfy these offset requirements. The ERCs that have been procured are detailed in Table 7-2.

Table 7-1
Emission Reduction Credits Determination

	NO_X	SO_X[2]	PM_{10}	$PM_{2.5}$[3,4]	CO	VOC[5]
Gross Emissions, lb/yr [1]	327,400	58,780	180,700	160,340	550,380	70,800
SJVAPCD Requirements						
Offset Threshold Levels per Section 4.5.3 of DR2201, lb/yr	20,000	54,750	29,200	200,000	200,000	20,000
Required ERCs, lb/yr	307,400	4,030	151,500	-39,660	350,380	50,800
Offsets Triggered?	yes	yes	yes	no	no[6]	yes
Offset Ratio (1:X)	1.5	1.5	1.5	NA	NA	1.3
Required ERCs, lb/yr	461,100	6,045	227,250	0	0	66,040
ERCs in Possession, lb/yr	522,400	266,000	0	0	0	77,498
Inter-pollutant offset, lb/yr	–	-236,000	236,000	–	–	–
ERCs Surplus (Needed), lb/yr	61,300	23,955	8,750	–	–	11,458
Additional Mitigation						
Required ERCs, lb/yr	327,400	58,780	180,700	0	0	70,800
ERCs in Possession, lb/yr	522,400	266,000	0	0	0	77,498
Inter-pollutant offset, lb/yr	–	-192,000	192,000	–	–	–
ERCs Surplus (Needed), lb/yr	195,000	15,220	11,300	–	–	6,698

[1] Gross emissions include emissions from the exempt emergency generators and fire pumps; therefore, for SJVAPCD, fewer ERCs would be required.
[2] Ratio of 1:1 used to apply SO_X certificates to PM_{10} emissions
[3] Major Source of $PM_{2.5}$ is defined as 100TPY as of July 15, 2008
[4] Federal and SJVAPCD New Source Review (NSR) offset trigger for $PM_{2.5}$ emissions is 100 TPY.
[5] Ratio of 1:1.3 used for VOCs, because source of VOC ERCs is within 15 miles of HECA project
[6] per Section 4.6.1 of DR2201, "Emission Offsets shall not be required for the following: Increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the Air Pollution Control Officer (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."

Table 7-2
ERCs Procured by HECA

Source	Address	Method of Reduction	ERC Certificate Number	Pollutant	lbs/yr
Big West of California, LLC	6500 Refinery Ave, Bakersfield, CA Section: NE27, Township: 29S, Range: 27E	Shut-down of Catalytic Cracker, Fluid Cocker, and CO Boiler	S-3273-2	NO_X	482,000
	6451 Rosedale Hwy, Area I, Bakersfield, CA Section: NE27, Township: 29S, Range: 27E	Shut-down of Tail Gas Incinerator, 2007027A	S-3275-5	SO_X	168,000
Aer Glan Energy LLC	20807 Stockdale Hwy, Bakersfield, CA Section: NE06, Township: 30S, Range: 26E	Shut-down of Entire Stationary Source	S-3605-1	VOC	31,748
			S-3557-1	VOC	45,750
G.I.C. Financial Services, Inc.	11535 E Mountain View Ave., Kingsburg, CA	Install Selective Catalytic Reduction, SCR, and Scrubber and convert from fuel oil to natural gas	C-1058-2	NO_X	40,400
			C-1058-5	SO_X	98,000

The Project will be constructed and operated in accordance with all laws, ordinances, regulations, and standards (LORS) applicable to protecting air quality and public health. USEPA has ultimate responsibility for ensuring, pursuant to the Clean Air Act Amendments of 1990 (CAAA), which areas of the U.S. meet, or are making progress toward meeting, the federal AAQS. Furthermore, the CAA, 42 United States Code 7401 *et seq*., as amended in 1977 and 1990, requires that the public be protected from unhealthful exposure to air pollutants. The State of California falls under the jurisdiction of USEPA Region IX, which is headquartered in San Francisco. USEPA requires that all states submit State Implementation Plans (SIPs) for non-attainment areas that describe how the federal AAQS will be achieved and maintained. Attainment plans must be approved by the CARB before they are submitted to USEPA.

Regional or local air quality management districts (or air districts), such as SJVAPCD are responsible for preparation of plans for attainment of federal and state air quality standards. CARB is responsible for overseeing attainment of the CAAQS, implementation of nearly all phases of California's motor vehicle emissions program, and oversight of the operations and programs of the regional air districts.

Each air district is responsible for establishing and implementing rules and control measures to achieve air quality attainment within its district boundaries. The air district also prepares an air quality management plan (AQMP) that includes an inventory of all emission sources within the district (both man-made and natural), a projection of future emissions growth, an evaluation of current air quality trends, and an assessment of any rules or control measures needed to attain the AAQS. This AQMP is submitted to CARB, which then compiles AQMPs from all air districts within the state into the SIP. The responsibility of the air districts is to maintain an effective permitting system for existing, new, and modified stationary sources, to monitor local air quality trends, and to adopt and enforce such rules and regulations as may be necessary to achieve the AAQS.

This CAA requires new sources that emit more than 10 tons per year of any specified HAP or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology. HECA will not emit more than 10 tons per year of any HAP, or more than 25 tons per year of any combination of HAPs.

Under the federal CAA, on April 16, 2012, USEPA promulgated a new NESHAP for both major HAPs and area sources for IGCC EGUs that limits emissions of mercury, hydrogen chloride, and filterable particulate matter. Emissions of these pollutants from the HECA Project will comply with this standard.

Applicable LORS related to the potential air quality and public health impacts from the Project are described below, and shown in Table 8-1. These LORS are administered (either independently or cooperatively) by the SJVAPCD, USEPA Region IX, CEC, and CARB. The area of responsibility for each of these agencies is described below. One of the principal objectives of this Permit Application is explain how the Proposed Project will comply with these LORS.

Table 8-1
Laws, Ordinances, Regulations, and Standards—Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
Federal		
Clean Air Act 160-169A and implementing regulations, Title 42 United States Code (USC) 7470-7492 (42 USC 7470-7492; Title 40 Code of Federal Regulations (CFR) Parts 51 and 52 (40 CFR Parts 51 and 52) Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of air pollution. PSD review applies to pollutants for which ambient concentrations are lower than NAAQS.	USEPA Region IX
Title 40 CFR Parts 70 and 71	This rule tailors GHG emissions to PSD and Title V permitting applicability criteria.	USEPA Region IX
CAA 171-193, 42 USC 7501 et seq. (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of stationary sources. NSR applies to pollutants for which ambient concentrations are higher than NAAQS.	USEPA Region IX
40 CFR Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year.	USEPA Region IX
CAA 401 (Title IV), 42 USC 7651 (Acid Rain Program); SJVAPCD Regulation II, Rule 2540	Requires reductions in NO_X and SO_2 emissions. Applicable to all stationary sources subject to Part 72, Title 40, Code of Federal Regulations (CFR).	SJVAPCD, with USEPA Region IX oversight
CAA 501 (Title V), 42 USC 7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	SJVAPCD, with USEPA Region IX oversight
CAA 111, 42 USC 7411, 40 CFR Part 60 (New Source Performance Standards, or NSPS)	Establishes national standards of performance for new stationary sources. This rule incorporates the New Source Performance Standards from Part 60, Chapter 1, Title 40, CFR.	SJVAPCD, with USEPA Region IX oversight
CAA 112	Requires protection of public health from unhealthful exposure to air pollutants.	USEPA, CARB, SJVAPCD

Table 8-1
Laws, Ordinances, Regulations, and Standards—Air Quality(Continued)

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
State		
California Code of Regulations, Title 17, Subchapter 10, Article 2, Sections 95100 et seq.	Requires mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (AB 32).	CARB
California Code of Regulations, Title 17, Subchapter 10, Article 5, Sections 95800-96023	Establishes a cap on GHG emissions and provides market-based compliance mechanisms (cap and trade program) for covered entities, including electrical generating units.	CARB
California Public Resources Code 25523(a); 20 CCR 1752, 2300 2309 and Div. 2, Chap. 5, Art. 1, Appendix B, Park (k) (CEC and CARB Memorandum of Understanding)	Requires that CEC's decision on the AFC includes requirements to assure protection of environmental quality; requires quantitative HRA, AFC is required to address air quality protection.	CEC
The California Global Warming Solutions Act of 2006. AB 32 (Stats. 2006; Chapter 488; H&SC 38500 et seq.)	Requires the ARB to enact standards that will reduce GHG emission to 1990 levels by 2020. Requires new baseload generation power plants to not exceed the rate of GHG emissions from a combined-cycle gas turbine plant.	CARB
California Code of Regulation. Title 20, §2902, Greenhouse Gases Emission Performance Standard.	The GHGs emission performance standard (EPS) applicable to this chapter is 1,100 pounds of CO_2 per megawatt hour of electricity.	CARB
California Code of Regulation. Title 20, §2903, Compliance with the Emission Performance Standard	A power plant's compliance with the EPS shall be determined by dividing the power plant's annual average CO_2 emissions in pounds by the power plant's annual average net electricity production in MWh.	CARB

Table 8-1
Laws, Ordinances, Regulations, and Standards—Air Quality(Continued)

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
California Code of Regulation. Title 20, §2904, Annual Average CO_2 Emissions	(a) Except as provided in Subsections (b) and (c), a power plant's annual average CO_2 emissions are the amount of CO_2 produced on an annual average basis by each fuel used in any component directly involved in electricity production, including, but not limited to, the boiler, combustion turbine, reciprocating or other engine, and fuel cell. The fuels used in this calculation shall include, but are not limited to, primary and secondary fuels, backup fuels, and pilot fuels, and the calculation shall assume that all carbon in the fuels is converted to CO_2. Fuels used in ancillary equipment, including, but not limited to, fire pumps, emergency generators, and vehicles shall not be included. (b) [not presented in this report because it pertains to biomass fuels and does not affect the Project] (c) For covered procurements that employ geological formation injection for CO_2 sequestration, the annual average CO_2 emissions shall not include the CO_2 emissions that are projected to be successfully sequestered. The EPS for such power plants shall be determined based on projections of net emissions over the life of the power plant. CO_2 emissions shall be considered successfully sequestered if the sequestration project meets the following requirements: (1) Includes the capture, transportation, and geologic formation injection of CO_2 emissions; (2) Complies with all applicable laws and regulations; and (3) Has an economically and technically feasible plan that will result in the permanent sequestration of CO_2 once the sequestration project is operational.	CARB
California Clean Air Act, TAC Program, H&SC § 39650, et seq.	Requires quantification of TAC emissions, use of BACT, and preparation of an HRA.	SJVAPCD with CARB oversight
H&SC, Part 6, § 44300 et seq. (Air Toxics "Hot Spots")	Requires inventorying of TACs and HRA, as well as public notification of predicted health risks.	SJVAPCD with CARB/OEHHA oversight
H&SC § 41700	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	SJVAPCD with CARB oversight

Table 8-1
Laws, Ordinances, Regulations, and Standards—Air Quality(Continued)

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
Local		
SJVAPCD Regulation II, Rule 2201 (New and Modified Stationary Source Review Rule)	This rule shall apply to all new stationary sources and all modifications to existing stationary sources which are subject to the District permit requirements and after construction emit or may emit one or more affected pollutant. The requirements of this rule in effect on the date the application is determined to be complete by the Air Pollution Control Officer (APCO) shall apply to such application except as provided in Section 2.1.	SJVAPCD
SJVAPCD Regulation II, Rule 2520 (Federally Mandated Operating Permits)	2.0 Applicability The provisions of this rule shall apply to the following sources: 2.1 Major air toxics sources, 2.2 Any stationary source that emits or has the potential to emit 100 tons per year of any air contaminant, 2.3 Any major source, 2.4 Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA published after July 21, 1992 except as provided for in section 4.2 of this rule. 2.4.1 For stationary sources, which are subject to Rule 2520 solely as a result of Section 2.4, only the emissions units within the a stationary source that are subject to the section 111 or 112 standard or requirement shall be subject to the Part 70 permitting requirements; 2.5 A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV of the CAA; 2.6 Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act; 2.7 A solid waste incinerator subject to a performance standard promulgated pursuant to section 111 or 129 of the CAA; and 2.8 Any source in a source category designated, pursuant to 40 CFR Part 70.3, by rule of the USEPA. 2.9 When calculating the potential to emit for the purpose of determining if the requirements of this rule are applicable, fugitive emissions must only be included for	SJVAPCD

Table 8-1
Laws, Ordinances, Regulations, and Standards—Air Quality(Continued)

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
	determining non-hazardous air pollutant emissions if the source is included in the list of source categories identified in the major source definition in 40 CFR part 70.2, or when determining if a stationary source is a major air toxics source.	
SJVAPCD Regulation II, Rule 2540	All stationary sources subject to Part 72, Title 40, Code of Federal Regulations (CFR)	SJVAPCD
SJVAPCD Regulation II, Rule 2550 (Federally Mandated Preconstruction Review for Major Sources of Air Toxics)	The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after 28 June 1998. Requirements for other projects that result in increases in emissions of hazardous air pollutants are addressed in the District's Risk Management Policy for Permitting New and Modified Sources.	SJVAPCD
SJVAPCD Regulation III	Identifies fees that are applicable to permit modifications, new facilities, and permitted emissions	SJVAPCD
SJVAPCD Regulation IV, Rule 4001	All new sources of air pollution and modification of existing sources of air pollution shall comply with the standards, criteria, and requirements set forth therein.	SJVAPCD
SJVAPCD Regulation IV, Rule 4002 (National Emission Standards for Hazardous Air Pollutants)	This rule incorporates the National Emission Standards for Hazardous Air Pollutants from Part 61, Chapter I, Subchapter C, Title 40, Code of Federal Regulations (CFR) and the National Emission Standards for Hazardous Air Pollutants for Source Categories from Part 63, Chapter I, Subchapter C, Title 40, Code of Federal Regulations (CFR). All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein.	SJVAPCD
SJVAPCD Regulation IV, Rule 4101 (Visible Emissions)	The provisions of this rule shall apply to any source operation which emits or may emit air contaminants.	SJVAPCD
SJVAPCD Regulation IV, Rule 4102 (Nuisance)	This rule shall apply to any source operation which emits or may emit air contaminants or other materials. Requires sources to not discharge air toxics detrimental to public health and prepare a HRA.	SJVAPCD
SJVAPCD Regulation IV, Rule 4201 (Particulate Matter Concentration)	This rule shall apply to any source operation which emits or may emit dust, fumes, or total suspended particulate matter.	SJVAPCD
SJVAPCD Regulation IV, Rule 4202 (Particulate Matter—Emission Rate)	This rule shall apply to any source operation which emits or may emit particulate matter emissions.	SJVAPCD

Table 8-1
Laws, Ordinances, Regulations, and Standards—Air Quality(Continued)

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
SJVAPCD Regulation IV, Rule 4301 (Fuel Burning Equipment)	The purpose of this rule is to limit the emission of air contaminants from fuel burning equipment. This rule limits the concentration of combustion contaminants and specifies maximum emission rates for sulfur dioxide, nitrogen oxides and combustion contaminant emissions.	SJVAPCD
SJVAPCD Regulation IV, Rule 4304 (Equipment Tuning Procedure)	The purpose of this rule is to provide an equipment tuning procedure for boilers, steam generators, and process heaters to control visible emissions and emissions of both nitrogen oxides (NO_X) and carbon monoxide (CO).	SJVAPCD
SJVAPCD Regulation IV, Rules 4305-4308 (Boilers, Steam Generators and Process Heaters)	The purpose of this rule is to limit emissions of nitrogen oxides (NO_X) and carbon monoxide (CO) from boilers, steam generators, and process heaters.	SJVAPCD
SJVAPCD Regulation IV, Rule 4311 (Flares)	The purpose of this regulation is to limit the emissions of volatile organic compounds (VOC), oxides of nitrogen (NO_X), and sulfur oxides (SO_X) from the operation of flares. This rule is applicable to operations involving the use of flares.	SJVAPCD
SJVAPCD Regulation IV, Rule 4320 (Boilers, Steam Generators and Process Heaters)	The purpose of this rule is to limit NO_X, CO, SO_2, and PM_{10} from boilers, steam generators, and process heaters.	SJVAPCD
SJVAPCD Regulation IV, Rule 4701 (Internal Combustion Engines)	Except as provided in Section 4.0, the provisions of this rule apply to any internal combustion engine rated greater than 50 brake horsepower (bhp) that requires a Permit to Operate (PTO).	SJVAPCD
SJVAPCD Regulation IV, Rule 4702 (Internal Combustion Engines)	This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.	SJVAPCD
SJVAPCD Regulation IV, 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.	SJVAPCD
SJVAPCD Regulation IV, Rule 4801 (Sulfur Compounds)	The provisions of this rule shall apply to any discharge to the atmosphere of sulfur compounds, which would exist as a liquid or a gas at standard conditions. 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: two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO_2), on a dry basis averaged over 15 consecutive minutes.	SJVAPCD

Table 8-1
Laws, Ordinances, Regulations, and Standards—Air Quality(Continued)

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
SJVAPCD Regulation VII, Rule 7012 (Hexavalent Chromium – Cooling Towers)	The requirements of this rule shall apply to any person who owns or operates or who plans to build, own, or operate a cooling tower in which the circulating water is exposed to the atmosphere.	SJVAPCD
SJVAPCD Regulation VIII	The purpose of Regulation VIII (Fugitive PM_{10} Prohibitions) is to reduce ambient concentrations of fine particulate matter (PM_{10}) by requiring actions to prevent, reduce or mitigate anthropogenic fugitive dust emissions. The Rules contained in this Regulation have been developed pursuant to U.S. Environmental Protection Agency guidance for Serious PM_{10} Non-attainment Areas. The rules are applicable to specified anthropogenic fugitive dust sources. Fugitive dust contains PM_{10} and particles larger than PM_{10}. Controlling fugitive dust emissions when visible emissions are detected will not prevent all PM_{10} emissions, but will substantially reduce PM_{10} emissions.	SJVAPCD
SJVAPCD Regulation IX	This Rule specifies the criteria and procedures for determining the conformity of federal actions with the San Joaquin Valley Air Pollution Control District's air quality implementation plan.	SJVAPCD
Industry		
None Applicable	None Applicable	

Source: HECA, 2012.

8.1 FEDERAL LORS

8.1.1 Ambient Air Quality Standards

USEPA, in response to the federal CAA of 1970, established federal AAQS in Title 40 CFR Part 50. The federal AAQS include both primary and secondary standards for six "criteria pollutants." These criteria pollutants are O_3, CO, NO_2, SO_2, particulate matter, and lead. Primary standards were established to protect human health, and secondary standards were designed to protect property and natural ecosystems from the effects of air pollution.

The 1990 CAAA established attainment deadlines for all designated areas that were not in attainment with the federal AAQS. In addition to the federal AAQS described above, a new federal standard for $PM_{2.5}$ and a revised O_3 standard were promulgated in July 1997. The new federal standards were challenged in a court case during 1998. The court required revisions in both standards before USEPA can enforce them. The U.S. Supreme Court upheld an appeal of the District Court decision in February 2001. These issues were resolved and the 1-hour O_3 standard revoked in 2005, while the revised $PM_{2.5}$ standard was made effective in 2006. In 2010 a new 1-hour SO_2 standard was implemented and the SO_2 24-hour and annual standards were revoked. The 3-hour secondary standard for SO_2 remains unchanged. The state of California has adopted CAAQS that are in some cases more stringent than the federal AAQS. The state and federal AAQS relevant to the Project are summarized in Table 8-2.

USEPA, CARB, and the local air pollution control districts determine air quality attainment status by comparing local ambient air quality measurements from the state or local ambient air monitoring stations with the federal and state AAQS. Those areas that meet ambient air quality standards are classified as "attainment" areas; areas that do not meet the standards are classified as "non-attainment" areas. Areas that have insufficient air quality data may be identified as unclassifiable areas. These attainment designations are determined on a pollutant-by-pollutant basis. The area around the Project Site is classified as attainment with respect to the NAAQS for NO_2, PM_{10}, CO, and SO_2, and non-attainment for O_3 and $PM_{2.5}$. With respect to CAAQS, the area around the Project Site is classified as attainment for NO_2, CO, sulfates, lead, H_2S, and SO_2, and non-attainment for O_3, PM_{10}, and $PM_{2.5}$. Nitrogen dioxide and SO_2 are regulated as PM_{10} precursors, and NO_2 and VOCs as O_3 precursors. Table 8-3 presents the attainment status (both federal and state) for SJVAB with respect to all criteria pollutants.

As mentioned above, both USEPA and CARB are involved with air quality management in the SJVAB, area along with SJVAPCD.

8.1.2 Prevention of Significant Deterioration Requirements

In addition to the AAQS described above, the federal PSD program has been established to protect deterioration of air quality in those areas that already meet NAAQS. The PSD program specifies allowable ambient pollutant concentration increases for attainment pollutants due to new emission sources. These increases allow economic growth while preserving the existing air quality, protecting public health and welfare, and protecting Class I areas. The PSD regulations require major stationary sources to undergo a pre-construction review that includes an analysis

Table 8-2
Relevant Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS[1]		CAAQS[2]
		Primary[3,4]	Secondary[3,5]	Concentration[3]
Ozone	1-hour	–	Same as primary standard	0.09 ppm (180 μg/m^3)
	8-hour	0.075 ppm (147 μg/m^3)		0.070 ppm (137 μg/m^3)
Carbon Monoxide	8-hour	9 ppm (10 mg/m^3)	None	9.0 ppm (10 mg/m^3)
	1-hour	35 ppm (40 mg/m^3)		20 ppm (23 mg/m^3)
Nitrogen Dioxide[6]	Annual average	0.053 ppm (100 μg/m^3)	Same as primary standard	0.030 ppm (57 μg/m^3)
	1-hour	0.100 ppm (188 μg/m^3)		0.18 ppm (339 μg/m^3)
Sulfur Dioxide[7]	Annual average	0.030 ppm (80 μg/m^3)[7]	–	–
	24-hour	0.14 ppm (365 μg/m^3)[7]	–	0.04 ppm (105 μg/m^3)
	3-hour	–	0.5 ppm (1,300 μg/m^3)	–
	1-hour	0.075 ppm (196 μg/m^3)	–	0.25 ppm (655 μg/m^3)
Respirable Particulate Matter (PM_{10})	24-hour	150 μg/m^3	Same as primary standard	50 μg/m^3
	Annual arithmetic mean	–		20 μg/m^3
Fine Particulate Matter ($PM_{2.5}$)	24-hour	35 μg/m^3	Same as primary standard	–
	Annual arithmetic mean	15 μg/m^3		12 μg/m^3
Lead[8,9]	30-day average	–	–	1.5 μg/m^3
	Calendar quarter	1.5 μg/m^3 (for certain areas)[9]	Same as primary standard	–
	Rolling 3-month average	0.15 μg/m^3		–

Table 8-2
Relevant Ambient Air Quality Standards (Continued)

Pollutant	Averaging Time	NAAQS[1]		CAAQS[2]
		Primary[3,4]	Secondary[3,5]	Concentration[3]
Vinyl Chloride[8]	24-hour	No federal standards		0.01 ppm (26 μg/m^3)
Hydrogen Sulfide	1-hour			0.03 ppm (42 μg/m^3)
Sulfates	24-hour			25 μg/m^3
Visibility Reducing Particles[10]	8-hour (10 am to 6 pm, Pacific Standard Time)			See footnote 10

Source: USEPA-NAAQS, http://www.epa.gov/air/criteria.html; CARB-CAAQS, http://www.arb.ca.gov/aqs/aaqs2.pdf

Notes:

1 National standards (other than ozone, particulate matter, and those based on annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth-highest 8-hour concentration measured at each site in a year, averaged over 3 years, is equal to or less than the standard. For PM_{10}, the 24-hour standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 μg/m^3 is equal to or less than one. For $PM_{2.5}$, the 24-hour standard is attained when 98 percent of the daily concentrations, averaged over 3 years, are equal to or less than the standard.

2 California standards for ozone, carbon monoxide (except 8-hour Lake Tahoe), sulfur dioxide (1- and 24-hour), nitrogen dioxide, and particulate matter (PM_{10}, $PM_{2.5}$, and visibility-reducing particles) are values that are not to be exceeded. All others are not to be equaled or exceeded. California ambient air quality standards are listed in the Table of Standards in § 70200 of Title 17 of the California Code of Regulations.

3 Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25°C and a reference pressure of 760 torr. Most measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 torr; ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.

4 National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health.

5 National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.

6 To attain the 1-hour national standard, the 3-year average of the annual 98th percentile of the 1-hour daily maximum concentrations at each site must not exceed 100 ppb.

7 On June 2, 2010, a new 1-hour SO_2 standard was established and the existing 24-hour and annual primary standards were revoked. To attain the 1-hour national standard, the 3-year average of the annual 99th percentile of the 1-hour daily maximum concentrations at each site must not exceed 75 ppb. The 1971 SO_2 national standards (24-hour and annual) remain in effect until 1 year after an area is designated for the 2010 standard, except that in areas designated non-attainment for the 1971 standards, the 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standards are approved.

8 The Air Resources Board has identified lead and vinyl chloride as "toxic air contaminants" with no threshold level of exposure for adverse health effects determined. These actions allow for the implementation of control measures at levels below the ambient concentrations specified for these pollutants.

9 The national standard for lead was revised on October 15, 2008 to a rolling 3-month average. The 1978 lead standard (1.5 μg/m^3 as a quarterly average) remains in effect until 1 year after an area is designated for the 2008 standard, except that in areas designated non-attainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.

10 In 1989, the ARB converted both the general statewide 10-mile visibility standard and the Lake Tahoe 30-mile visibility standard to instrumental equivalents, which are "extinction of 0.23 per kilometer" and "extinction of 0.07 per kilometer" for the statewide and Lake Tahoe Air Basin standards, respectively.

μg/m^3 = micrograms per cubic meter
°C = degrees Celsius
CAAQS = California Ambient Air Quality Standards
mg/m^3 = milligram per cubic meter
NAAQS = National Ambient Air Quality Standards
ppm = parts per million[3]

Table 8-3
Attainment Status for Kern County with Respect to Federal and California Ambient Air Quality Standards

Pollutant	Federal Attainment Status	State Attainment Status
Ozone	Extreme non-attainment	Non-attainment
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
PM_{10}	Attainment[1]	Non-attainment
$PM_{2.5}$	Non-attainment	Non-attainment
Lead	Unclassified	Attainment

Source: CARB (http://www.arb.ca.gov/desig/desig.htm); USEPA (http://www.epa.gov/air/oaqps/greenbk/index.html)

Notes:
[1] On 25 September 2008, USEPA redesignated the San Joaquin Valley to attainment for the PM_{10} National Ambient Air Quality Standard (NAAQS) and approved the PM_{10} Maintenance Plan.
CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
SO_2 = sulfur dioxide

and implementation of BACT, a PSD increment consumption analysis, an ambient air quality impact analysis, and analysis of AQRVs (impacts on visibility). Effective July 2011, a source that emits more than 75,000 tpy of CO_2e is also considered a major stationary source. The Project is subject to these requirements.

The PSD significant emission triggers for all pollutants are as shown in Table 8-4. Project emissions of CO, NO_X, and PM_{10} are above these PSD triggers, thus HECA LLC must demonstrate through modeling that such emissions will not interfere with the attainment or maintenance of the applicable NAAQS and will not cause an exceedance of the applicable PSD increments shown in Table 8-5. Modeling showed that PM_{10} 24-hour and annual, and NO_X annual impacts are below the PSD SILs, thus they are also below the increments listed in Table 8-5. For all Project emissions, HECA LLC demonstrated through modeling that the increase in emissions would not interfere with the attainment or maintenance of the NAAQS. These analyses were described in Section 4-2.

Project emissions of CO_2e are above the PSD applicability threshold; thus, a GHG BACT analysis must be conducted to ensure that GHG emissions are minimized and Project efficiency is maximized. This analysis is described in Section 3.3 and Appendix C, Greenhouse Gas BACT Analysis.

Table 8-4
PSD Emission Threshold Triggers for New Stationary Sources

Pollutant	Applicability Thresholds (tpy)	Significant Emission Rate (tpy)	Project Emissions (tpy)	PSD Triggered by Project?
CO	100	100	275	Yes
SO_2	100	40	29	No
NO_X	100	40	164	Yes
PM_{10}	100	15	90	Yes
$PM_{2.5}$	100	10	80	No[1]
VOCs	100	40	35	No
CO_2e	75,000	N/A	535,278	Yes
Lead (Pb)	N/A	0.6	0.007	No
Fluorides	N/A	3	0.001	No
Sulfuric acid mist	N/A	7	1.14	No
Hydrogen sulfide (H_2S)	N/A	10	2.64	No
Total reduced sulfur (TRS)	N/A	10	4.17	No
Reduced sulfur compounds	N/A	10	4.42	No

Source: 40 CFR § 52.21 and HECA 2012.
Notes:
[1] PSD is not triggered as the Project is in a non-attainment area for $PM_{2.5}$.
CO = carbon monoxide
CO_2e = carbon dioxide equivalent
NO_X = nitrogen dioxide
N/A = not applicable
Pb = lead
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
PM_{10} = particulate matter less than 10 microns in diameter
SO_2 = sulfur dioxide
tpy = tons per year
VOCs = volatile organic compounds

Table 8-5
Prevention of Significant Deterioration Allowable Increments
($\mu g/m^3$)

Standard	Class I Area	Class II Area	Class III Area
PM_{10} Annual Arithmetic Mean	4	17	34
PM_{10} 24-Hour Maximum	8	30	60
CO 8-Hour Maximum	N/A	N/A	N/A
CO 1-Hour Maximum	N/A	N/A	N/A
NO_2 Annual Arithmetic Mean	2.5	25	50
NO_2 1-Hour Maximum	TBD	TBD	TBD

Source: 40 CFR § 52.21.
Notes:
$\mu g/m^3$ = micrograms per cubic meter
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
CO = carbon monoxide
N/A = not applicable
TBD = to be determined

This application includes supplemental information for the PSD application that was submitted to USEPA in June 2009 that incorporates the new Project refinements and demonstrates compliance with the requirements listed above.

8.1.3 Acid Rain Program Requirements

Title IV of the CAAA applies to sources of air pollutants that contribute to acid rain formation, including certain sources of SO_2 and NO_X emissions. The SJVAPCD has been delegated authority by USEPA to administer Title IV requirements under its Title V Operating Permit program in Regulation II. Title IV is implemented by USEPA under 40 CFR 72, 73, and 75. The Acid Rain Program provisions of 40 CFR Part 72, Subparts A through I, are incorporated in SJVAPCD Rule 2540. Allowances of SO_2 emissions are set aside in 40 CFR 73. Sources subject to Title IV are required to obtain SO_2 allowances, to monitor their emissions, and obtain sufficient SO_2 allowances as part of the permitting process. Sources such as the Project that use fossil-derived fuel are required to comply with the acid rain program requirements. Under this program, HECA LLC is subject to the following requirements:

- Submittal of an Acid Rain permit application
- Remain in compliance with SO_2 and NO_X limitations/allowances
- Preparation and maintenance of an Acid Rain Compliance Plan
- Installation and maintenance of emission monitoring system.

The Project is a new facility; therefore, an Acid Rain Permit application will be submitted to SJVAPCD at least 24 months before the date of initial operation of the facility.

To meet the NO_X and SO_2 requirements, the Project must estimate SO_2 and NO_X emissions, and monitor NO_X emissions with certified CEMS.

8.1.4 New Source Performance Standards

NSPS have been established by USEPA to limit air pollutant emissions from certain types of new and modified stationary sources. The NSPS regulations are contained in 40 CFR 60, and cover nearly 70 source categories. CTG/HRSG is regulated under Subpart Da.

In general, local emission limitation rules or BACT requirements are more restrictive than the NSPS requirements. A case-by-case applicability of NSPS regulations for the sources is further discussed in the BACT analysis in Section 3.2 and Appendix B Criteria Pollutant BACT Analysis.

8.1.5 Federal Climate Change Programs

On April 13, 2012, the USEPA proposed the first Clean Air Act NSPS for emissions of CO_2 from future power plants (Standards for Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units). USEPA is proposing that new fossil-fuel-fired power plants meet an output-based standard of 1,000 pounds of CO_2 per megawatt-hour (lb CO_2/MWh gross). This rule is currently in the public comment phase and it is unclear when the rule will be finalized. The HECA facility emissions of GHG are compliant with the limit specified in the proposed rule.

USEPA issued the Mandatory Reporting of Greenhouse Gases Rule which requires reporting of GHG data and other relevant information from large sources and suppliers in the United States. The purpose of the rule is to collect accurate and timely GHG data to inform future policy decisions. In general, the Rule is referred to as 40 CFR Part 98 (Part 98). Implementation of Part 98 is referred to as the Greenhouse Gas Reporting Program. HECA will be subject to the requirements of this program.

8.1.6 Federally Mandated Operating Permits

Title V of the CAAA requires USEPA to develop a federal operating permit program that is implemented under 40 CFR 70. This program is administered by SJVAPCD under its Regulation II, Rule 2520. Each major source, Phase II acid rain facility, and other source types designated by USEPA must obtain a Part 70 permit. Permits must contain emission limits based on potential-to-emit, identification of all emission sources and controls, a compliance plan, and a statement indicating each source's compliance status. The permits must also incorporate and demonstrate compliance with all applicable federal, state, or SJVAPCD orders, rules, and regulations.

Because the Project will constitute a new stationary source, HECA LLC will submit a complete Title V permit application for a Title V permit to operate within 12 months after Project start-up.

8.1.7 General Conformity

The General Conformity Rule ensures that the actions taken by federal agencies in non-attainment and maintenance areas do not interfere with a state's plan to meet national standards for air quality. The purpose of the General Conformity Rule is to ensure that federal activities do

not cause or contribute a new violation of NAAQS and ensure that attainment of the NAAQS is not delayed. Therefore, federal entities are required to find that the total direct or indirect emissions from the federal action will conform to the purpose of the SIP or not otherwise interfere with the state's ability to attain and maintain the NAAQS. The General Conformity Rule may be implemented in coordination with and as part of the NEPA environmental review process. The proposed HECA Project is federally funded by the U.S. Department of Energy and is therefore subject to NEPA and the General Conformity Rule.

HECA Project emissions of CO, PM_{10}, $PM_{2.5}$, SO_2, and O_3 precursor (NO_X and VOC) during construction and operations of the HECA Project are subject to General Conformity requirements. Stationary source emissions are controlled by the SJVAPCD permit and are considered to comply with the SIP; therefore, the stationary source emissions are not included in the General Conformity analysis. The USEPA created *de minimis* emission levels for each criteria pollutant to limit the need to conduct conformity determinations for federal projects with minimal emission increases. The attainment status of the project area determines the *de minimis* levels that are applicable for a project. When the total direct and indirect emissions from a proposed project are below the *de minimis* levels, the project would not be subject to a conformity determination.

Applicability of the General Conformity rule is determined based on direct and indirect emissions from the proposed HECA Project, which include the contribution of off-site truck and rail transportation, on-site truck and rail transportation, and the commuting of worker vehicles. Vehicles servicing HECA will travel through many AQCRs in California (SJVAPCD, SCAQMD, EKAPCD, MDAQMD, Sacramento Metro area, Yuba City-Marysville area, Chico area), Oregon, Washington, Arizona, and New Mexico.

Preliminary project-related emissions of nonattainment and precursor pollutants were calculated for each AQCR along the expected transportation routes. It should be noted that not each of the affected air districts is non-attainment for the same non-attainment pollutants. The estimated annual emission rates in each AQCR were compared with the applicable *de minimis* thresholds. The emission increases due to Project-related transportation are expected to be less than the conformity *de minimis* levels in all areas, except SJVAPCD. The preliminary NO_X emission increase due to the proposed Project operation associated with transportation in SJVAPCD is greater than the *de minimis* level of 10 tpy. In addition, NO_X and VOC emissions during Project construction exceed the *de minimis* level of 10 TPY. Therefore, a conformity determination will be prepared by HECA LLC and reviewed by SJVAPCD for NO_X and VOC as precursors to ozone.

8.1.8 Hazardous Air Pollutants

The federal CAA of 1970, 42 United States Code 7401 *et seq*., as amended in 1977 and 1990, requires that the public be protected from unhealthful exposure to air pollutants. Based on the results of the risk assessment, health risks due to Project emissions of air toxics will not exceed acceptable levels. Emissions of criteria pollutants will be minimized by applying BACT to the facility. Increases in emissions of criteria pollutants will be fully offset.

This act requires new sources that emit more than 10 tons per year of any specified HAP or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology. HECA will not emit more than 10 tons per year of any HAP, or more than 25 tons per year of any combination of HAPs.

Under the federal CAA, on April 16, 2012, USEPA promulgated a new NESHAP for both major HAPs and area sources for IGCC EGUs that limits emissions of mercury, hydrogen chloride, and filterable particulate matter. Emissions of these pollutants from the HECA Project will comply with this standard.

8.2 STATE OF CALIFORNIA LORS

8.2.1 California Power Plants Siting Requirements

Under CEQA, CEC has been charged with assessing the environmental impacts of each new power plant and considering the implementation of feasible mitigation measures to prevent potential significant impacts. CEQA Guidelines (Title 14, California Administrative Code, §15002[a][3]) state that the basic purpose of CEQA is to "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."

CEC's siting regulations require that, except under certain conditions, a new power plant can only be approved if the project complies with all federal, state, and local air quality rules, regulations, standards, guidelines, and ordinances that govern the construction and operation of the project. A project must demonstrate that project emissions will be appropriately controlled to mitigate significant impacts from the project, and that it will not jeopardize attainment and maintenance of the AAQS. Cumulative impacts, impacts due to pollutant interaction, and impacts from non-criteria pollutants must also be considered. An Application for Certification for the HECA Project was submitted to CEC in May 2012, including a full accounting of the Project's emissions of air pollutants and potential impacts to air quality and public health.

8.2.2 California Climate Change Programs

Assembly Bill 32 (AB 32) requires CARB to enact standards that will reduce GHG emissions to 1990 levels by 2020. AB 32 requires CARB to assign emissions targets to each sector in the California economy and to develop regulatory and market methods to ensure compliance. Emission targets have been established in the CCR Title 20 §2902 – 2904. Additionally, Senate Bill (SB) 1368 is a state regulation that has set limits on GHG emissions from utilities. CEC is currently considering whether to modify the current requirements of SB 1368. SB 1368 set an emission performance standard for baseload generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb/MWh of CO_2. The Project will comply with the current version of SB 1368.

The GHG cap-and-trade regulation under AB 32 became effective January 2012, with a compliance date beginning January 1, 2013. Companies are not given a specific limit on their GHG emissions, but must supply a sufficient number of allowances to cover their annual emissions. As the cap declines each year, the total number of allowances issued in the state

decreases, requiring companies to find the most cost-effective and efficient approaches to reducing their emissions. CARB will provide allowances to industrial sources during the initial period (2013–2014), and those that need additional allowances to cover their emissions can purchase them on the market. Electric utilities will also be given allowances to be sold to power providers such as the Project.

8.2.3 Health Risk Assessment and Air Toxic "Hot Spots" Program

As required by the California Health and Safety Code §44300, all facilities with criteria air pollutant emissions in excess of 10 tons per year are required to submit air toxic "Hot Spots" emissions information. The operational Project will be required to provide quantitative information to the SJVAPCD on the Project's emissions of TACs. This requirement is applicable only after the start of operation. The HRA discussed in this Permit Application demonstrates that the Project's emissions of TACs impacts from the Project will be less than significant.

California Public Resource Code § 25523(a); 20 CCR § 1752.5, 2300-2309, and Division 2 Chapter 5, Article 1, Appendix B, Part (1), requires that protection of environmental quality be ensured, and that a quantitative HRA be performed. The HRA presented in Section 5 of this Application satisfies this requirement.

The CCAA, TAC Program, HSC § 39650, *et seq*. requires quantification of TAC emissions, use of BACT, and preparation of an HRA. The Project will not cause unsafe exposure to TACs based on results of the HRA discussed in this section, and a BACT assessment for the Project has been performed (see Section 3.2).

California Health and Safety Code § 41700 prohibits emissions in quantities that adversely affect public health, other businesses, or property. Section 5.1, Air Quality, and the HRA discussed in this Permit Application satisfy this requirement.

California Code of Regulations, Title 22, Section 60306 requires use of a drift eliminator and biocides to minimize the possibility of Legionella being transmitted from the cooling system.

8.2.4 Determination of Compliance, Authority to Construct, and Permit to Operate

Under Regulation II, Rule 2010, 2070, and 2201, the SJVAPCD administers the air quality regulatory program for the construction, alteration, replacement, and operation of new power plants. As part of the AFC process, the Project will be required to obtain a pre-construction Determination of Compliance (DOC) from the SJVAPCD. Regulation II, Rule 2201 incorporates other SJVAPCD rules that pertain to sources that may emit air contaminants through the issuance of air permits (i.e., ATC and Permit to Operate [PTO]). This permitting process allows the SJVAPCD to adequately review new and modified air pollution sources to ensure compliance with all applicable prohibitory rules and to ensure that appropriate emission controls are used. An ATC allows for the construction of the air pollution source, and remains in effect until the PTO application is granted, denied, or cancelled. Projects that are reviewed under the CEC application process must obtain an ATC from the local air district (in this case, SJVAPCD) prior to construction of the new power plant. For power plants under the siting

jurisdiction of CEC, the SJVAPCD issues a DOC in lieu of an ATC. The DOC is incorporated into the CEC license. The DOC remains in effect until the PTO application is granted, denied, or cancelled. Once the Project commences operations and demonstrates compliance with the DOC, SJVAPCD will issue a PTO. The PTO specifies conditions that the air pollution source must meet to comply and will incorporate applicable DOC requirements.

8.3 SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT REQUIREMENTS

The SJVAPCD has been delegated responsibility for implementing the federal, state, and local regulations on air quality in Kern County to achieve and maintain both state and federal air quality standards; implementing permit programs established for the construction, modification, and operation of sources of air pollution; enforcing air pollution statutes, regulations, and prohibitory rules governing non-vehicular sources; and developing programs to reduce emissions from indirect sources. The Project is subject to SJVAPCD regulations that apply to new sources of emissions, to the prohibitory regulations that specify emissions standards, and to the requirements for evaluation of air pollutant impacts for both criteria and toxic air pollutants. The following sections include the evaluation of the Project's compliance with the applicable SJVAPCD requirements.

8.3.1 SJVAPCD Climate Change Action Plan

In December 2009, the SJVAPCD adopted the "Guidance for Valley Land-use Agencies in Addressing GHG Emission Impacts for New Projects under CEQA" and the district policy "Addressing GHG Emission Impacts for Stationary Source Projects under CEQA When Serving as the Lead Agency" (SJVAPCD 2009a, 2009b). The guidance and policy rely on the use of performance based standards, otherwise known as Best Performance Standards, to assess significance of project-specific GHG emissions on global climate change during the environmental review process, as required by CEQA. This policy applies to projects for which the SJVAPCD has discretionary approval authority over the project, and the SJVAPCD serves as the lead agency for CEQA purposes. For this Project, CEC is the lead agency, and quantification of GHG emissions is used to determine compliance with adopted regional, statewide, or local GHG reductions plans. As such, the SJVAPCD Climate Change Plan performance-based standards are not applicable to this Project.

8.3.2 SJVAPCD Rules and Regulations

Rule 1080, Stack Monitoring

Outlines facility requirements for continuous monitoring equipment from any facility emitting pollutants for which emission limits have been established. The Project will be constructed and operated to comply with the requirements of Rule 1080.

Rule 1081, Source Sampling

Outlines facility design requirements for source sampling from any facility emitting pollutants for which emission limits have been established. The Project will be constructed and operated to comply with the requirements of Rule 1081.

Rule 1100, Equipment Breakdown

This rule details the notification and corrective action requirements necessary in an equipment breakdown situation. As operator of the Project, the Applicant will comply with these requirements.

Rule 2010, Permits Required

An ATC and PTO will be required for the Project. The Applicant will submit the required application materials for these permits to SJVAPCD.

Rule 2201, New and Modified Stationary Source Review

This rule outlines the emission standards, the offset requirements and conditions, the required demonstrations that the new source or modification will not cause or contribute to violations of the ambient air quality standards, procedures for power plants under the CEC licensing process, methods for calculating project emissions, and required air quality analysis procedures. Compliance with the specific provisions of this rule is discussed below.

Section 4.1, BACT. An Applicant must apply BACT to any new or modified emissions unit that has a potential to emit 2.0 pounds per day or more of any criteria pollutant. The SJVAPCD maintains a list of current BACT standards for specific source categories, which is posted on the District's website. Appendix B, Criteria Pollutant BACT Analysis, provides a formal BACT evaluation for the Project emissions of criteria pollutants. The proposed BACT levels for each Project source are shown in Table 3-1, Proposed BACT for the Project, and incorporated in the emission calculations.

The Project will produce low-carbon baseload electricity and nitrogen-based products by capturing CO_2 and transporting it for EOR and sequestration, thus controlling GHG emission to levels substantially below that of other fossil fuel power plants. The GHG BACT analysis for the HECA Project is presented in Appendix C, Greenhouse Gas BACT Analysis, and is summarized in Section 3.3 and Table 3-2, Summary of Proposed GHG BACT Permit Limits for HECA.

Section 4.5, Emissions Offset Requirements. This section of Rule 2201 requires that offsets be provided for a new stationary source with a potential to emit equal to or exceeding the triggering levels defined in the Rule. The ERC analysis presented in Section 7, Emission Reduction Credits Package, describes the methods for determining the quantities of emission reduction credits needed to offset emissions from the Project. HECA LLC has already procured sufficient ERCs to mitigate Project emissions of non-attainment pollutant and their precursors.

Section 4.14, Ambient Air Quality Standards. Emissions from a new or modified Stationary Source may not cause or make worse the violation of an AAQS. Modeling used for the purposes of demonstrating compliance with this rule must be consistent with the requirements contained in the most recent edition of USEPA's *Guidelines on Air Quality Models,* unless the APCO finds that such model is inappropriate for use. After making such a finding, the APCO may designate an alternate model only after allowing for public comments, and only with the concurrence of CARB or the USEPA.

As described in Section 4.2, Compliance with Ambient Air Quality Standards, an air quality modeling analysis has been conducted to demonstrate that the Project will not cause or make worse the violation of any air quality standard.

Section 5.8, Power Plants. This section applies to all power plants proposed to be constructed in the SJVAPCD, and for which a Notice of Intention or AFC has been accepted by CEC. It describes the actions to be taken by SJVAPCD to provide information to CEC and CARB to ensure that the Project will conform to the District's rules and regulations. After the application has been submitted to CEC and other responsible agencies, including SJVAPCD, the APCO is required to conduct a DOC review. This determination consists of a review identical to that which would be performed if an application for an ATC had been received for the power plant. If the information contained in the AFC does not meet the requirements of this regulation, then the APCO is required to so inform CEC within 20 calendar days following receipt of the AFC. In such an instance, the AFC is considered to be incomplete, and is returned to the Applicant for re-submittal.

Section 6.0, Certification of Conformity. This section describes how a new or modified source that is subject to the requirements of Rule 2520 may choose to apply for a Certificate of Conformity with the procedural requirements of 40 CFR Part 70 for a Federal Operating Permit. A Certificate of Conformity will allow changes authorized by the ATC permit to be incorporated in the Part 70 permit as administrative permit amendments.

Rule 2520, Federally Mandated Operating Permits

Provides an administrative mechanism for issuing operating permits for new and modified sources of air contamination accordance with the federal requirements of 40 CFR Part 70. Under this rule, the Project will be required to obtain an operating permit, because it will include emission units that are subject to recently promulgated NSPS, and because it will also require an acid rain permit.

Rule 3010/3020, Permit Fees

This rule and the fee schedules in Rule 3020 establish the filing and permit review fees for specific types of new sources, as well as annual renewal fees and penalty fees for existing sources.

Rule 3110, Air Toxics Fees

This rule applies to facilities subject to the requirements of the Air Toxics "Hot Spots" Information and Assessment Act (§§ 44340 and 44383 of the California Health and Safety Code), and to facilities subject to NESHAPs issued pursuant to §112 of the federal CAA.

Rule 3135, Dust Control Plan Fee

This rule recovers the District's cost for reviewing Dust Control Plans, and conducting site inspections to verify compliance with such plans.

Rule 3170, Federally Mandated Ozone Non-Attainment Fee

The purpose of this rule is to satisfy requirements specified in §185 and §1 82(f) of the CAA. This rule applies to major sources of NO_X and VOCs. The fees required pursuant to this section are additional to the permit fees and other fees required under other Rules and Regulations. This rule will cease to be effective when the Administrator of USEPA designates the SJVAPCD to be in attainment of the federal 1-hour standard for O_3. The Project will be a major source under either the federal or SJVAPCD definitions, and is subject to Rule 3170.

Rule 4001, New Source Performance Standards

This rule incorporates the federal NSPS from 40 CFR Part 60.

Rule 4002, National Emission Standards for Hazardous Air Pollutants

This rule incorporates the federal NESHAPs from Part 61 and Part 63, Chapter I, Subchapter C, Title 40 CFR.

Rule 4101, Visible Emissions

This rule applies to the opacity of discharges from any single source. Emissions from the sources of the Project will be below threshold opacity levels described in this rule.

Rule 4102, Nuisance

This rule states that there shall be no discharge of such quantities of any pollutant or material that could cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause or have a natural tendency to cause injury or damage to business or property. This rule requires an HRA to estimate the maximum potential public exposure and health risk for the purpose of approving the permit to operate and issuing public notice, if necessary. The HRA discussed in Section 5 satisfies this requirement.

Rule 4201, Particulate Matter Concentration

This rule applies to the discharge of particulate matter into the atmosphere. The relevant limit for the Project is expressed in Rule 4201, which states that no person shall release or discharge into the atmosphere from any single-source operation dust, fumes, or total suspended particulate matter, in excess of 0.1 gr/dscf of natural gas as determined by the following test methods: Particulate matter concentration – USEPA Method 5; Stack gas velocity – USEPA Method 2; Stack gas moisture – USEPA Method 4. The Project natural gas sources will easily comply with this requirement, with a maximum PM_{10} emission rate of approximately 0.045 gr/dscf of natural gas consumption.

Rule 4301, Fuel-Burning Equipment

This rule limits the emission levels of NO_X, SO_2, and fuel combustion contaminants (particulates) from any fuel-burning equipment unit. The specific limits are 140 pounds per hour of NO_X, calculated as NO_2, 200 pounds per hour of SO_2, 0.1 grain per cubic foot of gas

calculated to 12 percent of CO_2 at dry standard conditions, and 10 pounds per hour of combustion contaminants.

Rule 4703, Stationary Gas Turbines

This rule limits the NO_X and CO emissions from gas turbines with ratings greater than 0.3 MW. NO_X emissions concentrations shall be averaged over a 3-hour period using consecutive 15-minute sampling periods; or if CEMS are used, all applicable requirements of 40 CFR Part 60 must be met.

Rule 4801, Sulfur Compounds

This rule limits the emissions of sulfur compounds to less than 0.2 percent by volume on a dry basis averaged over 15 consecutive minutes by using USEPA Method 8 and CARB Methods 1 through 100.

Rule 8021, Construction, Demolition, Excavation, Extraction, and Other Earthmoving Activities

This rule limits fugitive dust emissions from construction, demolition, excavation, extraction, and other earthmoving activities such that opacity levels are kept to no more than 20 percent.

Rule 8041, Carryout and Trackout

This rule requires the limiting of carryout and trackout dust emissions from sites, and is applicable to construction of the Project.

Rule 8051, Open Areas

This rule applies to any open area of 3.0 acres or more in rural areas with at least 1,000 square feet of disturbed surface area. Dust emissions must be kept below 20 percent opacity.

Rule 8061, Paved and Unpaved Roads

This rule limits the emission of fugitive dust from roads to no more than 20 percent opacity through different control measures. Depending on traffic levels, the road must meet certain width requirements.

Rule 8071, Unpaved Vehicle/Equipment Traffic Areas

This rule limits the emission of fugitive dust to no more than 20 percent opacity through different control measures.

Rule 9110, General Conformity

This rule specifies the criteria and procedures for determining the conformity of federal actions with the SJVAPCD's air quality implementation plan. Provisions of 40 CFR parts 6 and 51 are included in this rule.

On November 30, 1993, the USEPA promulgated a set of regulations known as the General Conformity regulations (40 CFR 51 Subpart W) that include procedures and criteria for

determining whether a proposed federal action would conform to the applicable SIPs. The General Conformity Rule affects air pollutant emissions associated with actions that are federally funded, licensed, permitted, or approved, and ensures emissions do not contribute to air quality degradation or prevent the achievement of state and federal air quality goals.

The proposed HECA Project is federally funded by the DOE; therefore, it is subject to NEPA and the General Conformity Rule.

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Appendix A

SJVAPCD Forms

San Joaquin Valley Air Pollution Control District

www.valleyair.org

Permit Application For:

[x] AUTHORITY TO CONSTRUCT (ATC) - New Emission Unit
[ ] AUTHORITY TO CONSTRUCT (ATC) - Modification Of Emission Unit With Valid PTO/Valid ATC
[ ] AUTHORITY TO CONSTRUCT (ATC) - Renewal of Valid Authority to Construct
[ ] PERMIT TO OPERATE (PTO) - Existing Emission Unit Now Requiring a Permit to Operate

1. PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC

2. MAILING ADDRESS:
STREET/P.O. BOX: 30 Monument Square, Suite 235
CITY: Concord STATE: MA 9-DIGIT ZIP CODE: 01742

3. LOCATION WHERE THE EQUIPMENT WILL BE OPERATED:
STREET: CITY:
Section 10 of Township 30 South, Range 24 East in Kern County and the associated APNs are part of 159-040-02, part of 159-040-16 and part of 159-040-18

WITHIN 1,000 FT OF A SCHOOL? [ ] YES [x] NO

S.I.C. CODE(S) OF FACILITY (*If known*):

4. GENERAL NATURE OF BUSINESS: Integrated Gasification and Combined Cycle Power Plant and Manufacturing Complex

INSTALL DATE:

5. TITLE V PERMIT HOLDERS ONLY: Do you request a COC (EPA Review) prior to receiving your ATC (*If yes, please complete and attach a Compliance Certification form (TVFORM-009)*)? [ ] YES [ ] NO

6. DESCRIPTION OF EQUIPMENT OR MODIFICATION FOR WHICH APPLICATION IS MADE (include Permit #'s if known, and use additional sheets if necessary)
See Section 2 of the Application Package

7. PERMIT REVIEW PERIOD: Do you request a three- or ten-day period to review the draft Authority to Construct permit? Please note that checking "YES" will delay issuance of your final permit by a corresponding number of working days. See instructions for more information on this review process.
[ ] 3-day review
[ ] 10-day review
[ ] No review requested

8. HAVE YOU EVER APPLIED FOR AN ATC OR PTO IN THE PAST? [x] YES [ ] NO
If yes, ATC/PTO #: S-1093741

9. IS THIS APPLICATION FOR THE CONSTRUCTION OF A NEW FACILITY? [x] YES [ ] NO
(If "Yes" is checked, please complete the CEQA Information form)

10. IS THIS APPLICATION SUBMITTED AS THE RESULT OF EITHER A NOTICE OF VIOLATION OR A NOTICE TO COMPLY? [ ] YES [x] NO
If yes, NOV/NTC #:

Optional Section

11. DO YOU WANT TO RECEIVE INFORMATION ABOUT EITHER OF THE FOLLOWING VOLUNTARY PROGRAMS?
[ ] "HEALTHY AIR LIVING (HAL) BUSINESS PARTNER"
[ ] "INSPECT"

12. TYPE OR PRINT NAME OF APPLICANT: James Croyle
James L. Croyle

TITLE OF APPLICANT: Chief Executive Officer

13. SIGNATURE OF APPLICANT: DATE: 5/31/12

PHONE #: (978) 287-9529
FAX #: (978) 287-9512
E-MAIL: JCroyle@scsenergyllc.com

FOR APCD USE ONLY:

DATE STAMP:

FILING FEE RECEIVED: $ CHECK #:
DATE PAID:
PROJECT #: FACILITY ID:

San Joaquin Valley Air Pollution Control District
Supplemental Application Form

CEQA Information

The San Joaquin Valley Air Pollution Control District (District) is required by state law, the California Environmental Quality Act (CEQA), to review discretionary permit project applications for potential air quality and other environmental impacts. This form is a screening tool to assist the District in clarifying whether or not the project has the potential to generate significant adverse environmental impacts that might require preparation of a CEQA document (CEQA Guidelines §15060(a).

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County and the associated APNs are part of 159-040-02, part of 159-040-16 and part of 159-040-18

Section 1: Agency Approvals

	Check "Yes" or "No" as applicable.	**Yes**	**No**
1.	Has a Lead Agency prepared an environmental review document (Environmental Impact Review, Mitigated Negative Declaration, Negative Declaration, or Notice of Exemption) for this project?	☐ *Note 1*	☒
2.	Is a Lead Agency in the process of preparing an environmental review document (Environmental Impact Review, Mitigated Negative Declaration, Negative Declaration, or Notice of Exemption) for this project?	☒ *Note 1*	☐
	*If "**Yes**" is checked for either question 1 or 2, please provide the following information:* - *Lead Agency name : California Energy Commission* - *Name of Lead Agency contact person: __Bob Worl_____* - *Type of CEQA document prepared: Application for Certification* - *Project reference number: __08-AFC-8A_____* - *If a CEQA Environmental Review document has been prepared for this project, **please attach a copy of the Notice of Determination or the Notice of Exemption*** *If "**No**" is checked for both questions 1 and 2, please attach an explanation*:		

Note 1: If you answered YES to question 1 OR 2 do not complete Section 2 of this form, and please return the completed form to the Air Pollution Control District.

Section 2: Project Information

	Note: If you answered YES to question 1 OR 2 of Section 1 do not complete this section, and please return the completed form to the Air Pollution Control District.	**Yes**	**No**
1.	Would this project result in more than 47 heavy-duty truck (HD) one-way trips per day to and from the facility? (23 heavy-duty truck (HD) round trips per day).	☐	☐
2.	Would this project result in a need for more than 350 new employees?	☐	☐
3.	Would this project result in more than 700 customer trips per day to and from the facility?	☐	☐
4.	Would this project increase the demand for water at the facility by more than 5,000,000 gallons per day?	☐	☐
5.	Would this project require construction of new water conveyance infrastructure *Post-project facility water demand exceeding the capacity of local water purveyor.*	☐	☐
6.	Would this project create a permanent need for new or additional public services for Solid Waste Disposal or Hazardous Waste Disposal? *Post-project waste discharge exceeding the capacity of the local Solid Waste Disposal or Hazardous Waste Disposal.*	☐	☐
7.	Would this project result in noticeable off-site odors that have the potential to generate nuisance complaints?	☐	☐
8.	Would this project include equipment with a noise specification greater than 90 decibels (db)?	☐	☐
9.	Has this project generated any known public concern regarding potential adverse impacts? *Public concern may be interpreted as concerns by local groups at public meetings, adverse media attention such as negative newspapers or other periodical publications, local news programs, environmental justice issues, etc.*	☐	☐
10.	Would this project result in any demolition, excavation, and/or grading/construction activities outside the perimeter of the existing facility?	☐	☐
11.	Would this project result in any demolition, excavating, and/or grading construction activities that encompass an area exceeding 20,000 Square feet (inside or outside the perimeter of the existing facility)?	☐	☐
12.	Is this project part of a larger development activity at the facility that collectively would result in answering YES to any of the questions listed above?	☐	☐

FOR DISTRICT USE ONLY – CEQA ANALYSIS REQUEST

PERMIT	**TECHNICAL SERVICES**
AQE Name:	AQS Name:
Facility Name:	CEQA #: PAS#:
Facility #: Project #:	Project with potential public concern?: ☐ Yes ☐ No
Project subject to Public Notice?: ☐ Yes ☐ No	Detailed CEQA analysis required?: ☐ Yes ☐ No
Please summarize or attach the following: - ☐ Copy of application form - ☐ Project Location - ☐ SSIPE calculation - ☐ Project Description - ☐ GHG Determination (>230MT-CO_2e/yr? BPS?) - ☐ Expected date of ATC(s) issuance: _____	- ☐ CEQA paragraph sent to permit engineer - ☐ NOD prepared - ☐ County filing fees District check prepared - ☐ Game and Fish fees District check or proof of payment *(District check prepared after receiving applicant check)* - ☐ Ok to issue ATC
Date form is forwarded to Tech. Services SVr:	Date form is forwarded back to permit engineer:

San Joaquin Valley Air Pollution Control District
Supplemental Application Form

Gas Turbines

Please complete one form for each gas turbine.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

EQUIPMENT DESCRIPTION

Equipment Details	☒ Industrial Frame ☐ Aero Derivative ☐ Other: _____		
	Manufacturer: MHI	Model: 501GAC	Serial Number: TBD
	☐ Simple Cycle ☒ Combined Cycle ☐ Co-generation ☐ Other: _____		
	Nominal (ISO) Rating: 405 gross MW (at 1 atm, 59°F, 60% Relative Humidity)		
	Is the unit equipped with an auxiliary/duct burner? ☒ Yes ☐ No (Note: If yes, please complete a *Boiler, Steam Generator, Dryer, and Process Heater Supplemental Application form* for the unit.)		
Rule 4703 Type of Use and Emissions Monitoring Provisions	☐ Peaking Unit - limited to no more than 877 hrs/yr of operation ☐ Emergency Standby - limited to less than 200 hrs/yr of operation ☒ Full Time - must have either a Continuous Emission Monitoring System (CEMS) or an alternate emissions monitoring plan (must be approved by the APCO) ☒ CEMS, please specify all pollutants monitored: ☒ NO_x ☒ CO ☒ O_2 ☐ Other: _____ ☐ Alternate Emissions Monitoring Plan (please provide details in additional documentation)		
Fuel Use Meter	☒ Gaseous Fuel Meter ☐ Liquid Fuel Meter ☐ None		
Process Data	Will this unit be used in an electric utility rate reduction program? ☐ Yes ☒ No		
Combustor(s)	Manufacturer: MHI	Model: 501GAC	Number of Combustors: 1
	Maximum Heat Input Rating (for all combustors @ ISO standard conditions): 2537 x 10^6 Btu/hr HHV duct burner 315 x 10^6 Btu/hr		
	Water Injection: ☐ Yes ☐ No	Dry Low NO_x Technology: ☐ Yes ☒ No	
	Steam Injection: ☒ Yes ☐ No For natural gas	Other NO_x Control Technology: Direct nitrogen injection (H2 rich fuel); Selective Catalytic Reduction	

EMISSIONS DATA

Note: See District BACT and District Rule 4703 requirements for applicability to proposed unit at http://www.valleyair.org/busind/pto/bact/chapter3.pdf and http://www.valleyair.org/rules/currntrules/r4703.pdf						
Primary Fuel	Fuel Type: ☐ Natural Gas ☐ LPG/Propane ☐ Diesel ☒ Other: Hydrogen-Rich Fuel					
	Higher Heating Value: _____ Btu/gal or 289 Btu/scf			Sulfur Content: < 10 ppmv		
	Maximum Fuel Use @ HHV: _____ scf/hr or _____gal/hr			Rated Efficiency (EFF_{Mfg}): _____ %		
Primary Fuel Emissions Data	Operational Mode	Steady State (ppmv)	Steady State (lb/MMBtu)	Start-up (ppmv)	Start-up (lb/hr)	Shutdown (ppmv)	Shutdown (lb/hr)
	Nitrogen Oxides	2.5	0.011		66.6		66.6
	Carbon Monoxide	3	0.008		81		81
	Volatile Organic Compounds	1	0.0015		4.6		4.6
	Duration			24 hr/day	100 hr/yr	4 hr/day	8 hr/yr
	% O_2, dry basis, if corrected to other than 15%: 15 %						

EMISSIONS DATA (continued)

Secondary Fuel	When will the secondary fuel be used? ☒ Primary fuel curtailment ☐ Simultaneously with primary fuel ☐ Other: _____					
	Fuel Type: ☒ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf		Sulfur Content: __<= 12.65 ppmv			
	Maximum Fuel Use @ HHV: _____ scf/hr or _____gal/hr		Rated Efficiency (EFF_{Mfg}): _____ %			
Secondary Fuel Emissions Data	Operational Mode	Steady State (ppmv)	Steady State (lb/MMBtu)	Start-up (ppmv)	Start-up (lb/hr)	Shutdown (ppmv)	Shutdown (lb/hr)
	Nitrogen Oxides	4	0.015		107.2		122
	Carbon Monoxide	5	0.011		1135		2270
	Volatile Organic Compounds	2	0.003		32.4		65
	Duration (please provide justification)			__2.5 hr/day	__5 hr/yr	__5 hr/day	__10 hr/yr
	% O_2, dry basis, if corrected to other than 15%: __15 %						
Source of Data	☒ Manufacturer's Specifications ☐ Emission Source Test ☐ Other _____ (please provide copies)						

EMISSIONS CONTROL

Emissions Control Equipment (Check all that apply)	☒ Inlet Air Filter/Cooler ☒ Lube Oil Vent Coalescer
	☒ Selective Catalytic Reduction - Manufacturer: TBD Model: TBD ☒ Ammonia (NH_3) ☐ Urea ☐ Other: _____
	☒ Oxidation Catalyst - Manufacturer: TBD Model: TBD
	Control Efficiencies: NO_x 2.5 ppmv (H_2), 4ppmv (nat gas) CO 3 ppmv (H_2 rich); 5 ppmv (nat gas)
	☐ Other (please specify):
	For units equipped with exhaust gas NO_x control equipment and rated < 10 MW, or rated ≥ 10 MW but operated < 4,000 hr/yr, one may choose at least one of the following alternate emission monitoring schemes in lieu of a CEMS (each option below must be approved by APCO on a case-by-case basis. Please include a detailed proposal for each option chosen): ☐ Periodic NO_x emission concentration ☐ Turbine exhaust O_2 concentration ☐ Air-to-Fuel ratio ☐ Flow rate of reducing agents added to turbine exhaust ☐ Catalyst inlet and outlet temperature ☐ Catalyst inlet and exhaust O_2 conc. ☐ Other operational characteristics as approved by the APCO (specify on attached sheet)

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: __24 hours per day, and _____8,459 hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	__213_____ feet above grade	
	Stack Diameter	__276 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: 1,017,162 – 1,419,360 acfm	Temperature: ___200 °F	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

FOR DISTRICT USE ONLY

Date:	**FID:**	**Project:**	**Public Notice: [ ] Yes [ ] No**
Comments:			

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Coal Dryer Baghouse)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [x] Teflon [ ] Other:__TBD_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer: TBD	Model No. TBD
	Power Rating: TBD (Horsepower)	Air Flow Rate: TBD (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Coal dryer
Type of material collected by the baghouse/dust collector: HRSG Flue Gas with coal and petcoke particles
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____7,500___ tons/day (combination coal and petcoke)
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Coal Dryer	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: ___24 hours per day, and _____8,110 hours per year		
	☐ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___305 feet above grade	
	Stack Diameter	___192 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___231,000-235,000 acfm	Temperature: __200 °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District
Supplemental Application Form

Boilers, Steam Generators, Dryers, and Process Heaters

Please complete one form for each different piece of equipment.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC	
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County	

EQUIPMENT DESCRIPTION (Aux Boiler)

Equipment Details	☒ Boiler ☐ Steam Generator ☐ Dryer ☐ Process Heater ☐ Refinery Unit ☐ Other: _____	
	Manufacturer: TBD	
	Model: TBD	Serial Number: TBD
	Steam: ___150,000 pph, at __725 psig _____750ºF	
	Is this a "Load-Following" unit? ☐ Yes ☒ No (Note: A load following unit is a unit with normal operational load fluctuations and requirements which exceed the operational response range of an Ultra-Low NO_X burner system operating at 9 ppmv NO_X.)	
	☐ Indirect-Fired ☒ Direct-Fired	
	Flue Gas Recirculation: ☒ Forced FGR ☐ Induced FGR ☐ None	
	Is an O_2 Controller present? ☒ No ☐ Yes, Manufacturer:	
Rules 4305/4306 Type of Use and Emissions Monitoring Provisions	☐ Low Use - limited to less than 9 billion Btu/year, must have fuel use meter ☐ Tune the unit at least twice per calendar year in accordance with District Rule 4304 ☐ Operate the unit in a manner that maintains exhaust O_2 concentration ≤ 3.00% by volume on a dry basis ☐ Limited Use - limited from 9 billion Btu/year to 30 billion Btu/year, must have fuel use meter ☒ Full Time - limited from greater than 30 billion Btu/year to full time operation (8,760 hrs/year)	
	Note: Low Use units must identify operational characteristics recommended by the manufacturer, which can be monitored on a monthly basis (please provide details in additional documentation).	
	Note: Limited Use or Full Time units must have either a Continuous Emission Monitoring System (CEMS) or one of the following alternate emissions monitoring plans ☐ CEMS, please specify all pollutants monitored: ☐ NO_x ☐ CO ☐ O_2 ☐ Other: _____ ☒ Monitoring of NO_x, CO, and O_2 concentrations ☐ Periodic determination of flue gas recirculation rate by temperature measurement ☐ Periodic determination of flue gas recirculation rate by O_2 measurement ☐ Monitoring of burner mechanical adjustments and O_2 concentration ☐ Monitoring of the flue gas recirculation valve(s) setting ☐ Other Alternate Monitoring Plan (approved on a case by case basis), attach details	
	Note: See District policy (SSP-1105) for additional details of pre-approved alternate emissions monitoring plans, at: http://www.valleyair.org/policies_per/Policies/SSP 1105.pdf	
Fuel Use Meter	☒ Gaseous Fuel Meter ☐ Liquid Fuel Meter ☐ None	
Primary Burner	Manufacturer: TBD	Type: ☐ Standard ☐ Low NO_x ☒ Ultra Low NO_x
	Model: TBD	Serial Number: TBD
	Maximum Heat Input Rating: ____213 MMBtu/hr	Annual Heat Input: ____466 billion Btu/year
Secondary Burner (if more than one burner is present)	Manufacturer:	Type: ☐ Standard ☐ Low NO_x ☐ Ultra Low NO_x
	Model:	Serial Number:
	Maximum Heat Input Rating: _____ MMBtu/hr	Annual Heat Input: _____ billion Btu/year

EMISSIONS DATA

Note: See District BACT and District Rules 4305 and 4306 requirements for applicability to proposed unit at http://www.valleyair.org/busind/pto/bact/chapter1.pdf, http://www.valleyair.org/rules/currntrules/r4305.pdf, and http://www.valleyair.org/rules/currntrules/r4306.pdf.

Primary Fuel	Fuel Type: ☒ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or __1,020-1,050 Btu/scf		Sulfur Content: __12.65 ppmv			
Primary Fuel Emissions Data	Operational Mode	Steady State (ppmv)	Steady State (lb/MMBtu)	Start-up (ppmv)	Start-up (lb/hr)	Shutdown (ppmv)	Shutdown (lb/hr)
	Nitrogen Oxides	5	0.006				
	Carbon Monoxide	50	7.9				
	Volatile Organic Compounds		0.85				
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day	_____ hr/yr
	% O_2, dry basis, if corrected to other than 3%: ___3 %						
Secondary Fuel	Fuel Type: ☐ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf		Sulfur Content: _____ % by weight or _____ gr/scf			
	How will the secondary fuel be used? ☐ Secondary full-time fuel ☐ Backup for primary fuel ☐ Other: _____					
Secondary Fuel Emissions Data	Operational Mode	Steady State (ppmv)	Steady State (lb/MMBtu)	Start-up (ppmv)	Start-up (lb/hr)	Shutdown (ppmv)	Shutdown (lb/hr)
	Nitrogen Oxides						
	Carbon Monoxide						
	Volatile Organic Compounds						
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day	_____ hr/yr
	% O_2, dry basis, if corrected to other than 3%: _____ %						
Source of Data	☒ Manufacturer's Specifications ☐ Emission Source Test ☐ Other _____ (please provide copies)					
Additional Emissions Control Equipment	☒ Selective Catalytic Reduction - Manufacturer: ____TBD____ Model: ____TBD____ ☒ Ammonia (NH_3) ☐ Urea ☐ Other: _____					
	☐ Non-Selective Catalytic Reduction - Manufacturer: _____ Model: _____					
	Control Efficiencies: NO_x _____ %, SO_x _____ %, PM_{10} _____ %, CO _____ %, VOC _____ %					
	☐ Other (please specify):					

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and 2,190 hours per year Maximum annual capacity factor of 25%		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___80 feet above grade	
	Stack Diameter	___54 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___28,800 acfm	Temperature: __300 °F	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

FOR DISTRICT USE ONLY

Date:	**FID:**	**Project:**	**Public Notice: [ ] Yes [ ] No**
Comments:			

San Joaquin Valley Unified Air Pollution Control District
Supplemental Application Form

Flares

Please complete one form for each flare.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
FLARE LOCATION (STREET ADDRESS or ¼ SECTION, TOWNSHIP, & RANGE): Section 10 of Township 30 South, Range 24 East in Kern County

PROCESS DESCRIPTION

Process Data	Gas Streams/Processes the Flare Serves (include permit number(s), if applicable): Gasification Block including startup and shutdown; short term combustion turbine outages; other unplanned events	
	Is the flare gas pressure ≥ 5 psig? ☒ Yes ☐ No	
	Maximum Potential Flare Gas Flowrate: 3,000 MMBtu/hr acf/hr, _____ acf/day, 75,000 MMBtu/yr acf/year	
	Is this a municipal landfill flare? ☐ Yes ☒ No	Is this an emergency flare? ☒ Yes ☐ No

EQUIPMENT DESCRIPTION

Tip Data	Tip Manufacturer: TBD	Tip Model: TBD
	Serial No.: TBD	Tip Manufacturer's rated capacity: TBD (MMcf/hr)
	Tip Opening Cross Sectional Area: 75.4 (ft2)	
	Is this a ground level flare? ☐ Yes ☒ No	Is this an enclosed flare? ☐ Yes ☒ No
Flare Design and Emission Control Equipment	☐ Air-assist flare, _____ scfm of assist air	
	☐ Steam assist flare, _____ lb/min of assist steam	
	☐ Coanda effect flare	
	☒ Other type of flare (please provide details): Natural Gas Assist (if required)	
	Smokeless Operation? ☒ Yes ☐ No, Source: Supplier's experience	
Flare Emissions Data	NO_X Emission Factor: 0.12 / 0.07 (lb/MMBtu)	
	PM_{10} Emission Factor: 0.003 (lb/MMBtu)	
	CO Emission Factor: 0.08 / 2.0 / 0.37 (lb/MMBtu)	
	VOC Emission Factor: 0.0013 (lb/MMBtu)	
	VOC destruction efficiency: 99 %	
Source of Data	☒ Manufacturer's Specifications ☐ Emissions Source Test ☐ AP-42 ☐ Other _____ **Note: please provide copies of all sources of emissions data.**	

FLARED GAS DATA

Flared Gas Data	Fuel Type:	
	Flare Gas Fuel Flow Meter? ☐ Yes ☒ No	
	Higher Heating Value: __variable__ Btu/scf	Sulfur Content: _negligible_ gr/100 scf
	Carbon to Hydrogen ratio:	
	Percent weight of hydrocarbons heavier than pentane (please attach gas analysis):	

PILOT EQUIPMENT AND FUEL DATA

Pilot Type	Intermittent ☐	Continuous ☒	Automatic (Flow Sensing) Ignition System ☐	Heat Sensing Ignition System ☐
Pilot Fuel Data	Type of pilot gas fuel (e.g., LPG/propane, methane, or process gas stream): Natural Gas			
	Pilot Fuel Consumption: __0.5 MMBtu/hr___ (scf/hr)		Sulfur Content: __<= 0.75__ gr/100 scf	
	Pilot Gas Fuel Flow Meter: ☐ Yes ☐ No			

GAS SULFUR TREATMENT (if applicable)

Sulfur Treatment System	Type of system (submit manufacturer's documentation):
	Control Efficiency:_____ %, Source:
	Outlet sulfur concentration: _____ ppmw or gr-S/100 scf, Source:

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: _24_____ hours per day, and _28_____ hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed flare location to the nearest property line of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the flare to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed flare location to the nearest property line of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the flare to the receptor, i.e. North or Southwest.
Exhaust Parameters	Release Height	_250____ feet above grade	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____ ° from vert. or _____ ° from horiz.	
Exhaust Data	Flowrate: _____ acfm	Temperature: _(N/A)_____ °F	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

San Joaquin Valley Unified Air Pollution Control District
Supplemental Application Form

Flares

Please complete one form for each flare.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
FLARE LOCATION (STREET ADDRESS or ¼ SECTION, TOWNSHIP, & RANGE): Section 10 of Township 30 South, Range 24 East in Kern County

PROCESS DESCRIPTION

Process Data	Gas Streams/Processes the Flare Serves (include permit number(s), if applicable): emergency elevated flare with natural gas pilot primarily serving Rectisol unit	
	Is the flare gas pressure ≥ 5 psig? ☐ Yes ☒ No	
	Maximum Potential Flare Gas Flowrate: 430 MMBtu/hr acf/hr, _____ acf/day, 20,000 MMBtu/yr acf/year	
	Is this a municipal landfill flare? ☐ Yes ☒ No	Is this an emergency flare? ☒ Yes ☐ No

EQUIPMENT DESCRIPTION

Tip Data	Tip Manufacturer: TBD	Tip Model: TBD
	Serial No.: TBD	Tip Manufacturer's rated capacity: TBD (MMcf/hr)
	Tip Opening Cross Sectional Area: 1.33 (ft2)	
	Is this a ground level flare? ☐ Yes ☒ No	Is this an enclosed flare? ☐ Yes ☒ No
Flare Design and Emission Control Equipment	☐ Air-assist flare, _____ scfm of assist air	
	☐ Steam assist flare, _____ lb/min of assist steam	
	☐ Coanda effect flare	
	☒ Other type of flare (please provide details): Natural Gas Assist	
	Smokeless Operation? ☒ Yes ☐ No, Source: Supplier's experience	
Flare Emissions Data	NO_X Emission Factor: 0.12 (lb/MMBtu)	
	PM_{10} Emission Factor: 0.003 (lb/MMBtu)	
	CO Emission Factor: 0.08 (lb/MMBtu)	
	VOC Emission Factor: 0.0013 (lb/MMBtu)	
	VOC destruction efficiency: 99 %	
Source of Data	☒ Manufacturer's Specifications ☐ Emissions Source Test ☐ AP-42 ☐ Other _____ **Note: please provide copies of all sources of emissions data.**	

FLARED GAS DATA

Flared Gas Data	Fuel Type: natural gas	
	Flare Gas Fuel Flow Meter? ☐ Yes ☒ No	
	Higher Heating Value: 1,020 Btu/scf	Sulfur Content: 50 ppmv gr/100 scf
	Carbon to Hydrogen ratio:	
	Percent weight of hydrocarbons heavier than pentane (please attach gas analysis):	

PILOT EQUIPMENT AND FUEL DATA

Pilot Type	Intermittent ☐	Continuous ☒	Automatic (Flow Sensing) Ignition System ☐	Heat Sensing Ignition System ☐
Pilot Fuel Data	Type of pilot gas fuel (e.g., LPG/propane, methane, or process gas stream): Natural Gas			
	Pilot Fuel Consumption: 0.3 MMBtu/hr (scf/hr)		Sulfur Content: <= 0.75 gr/100 scf	
	Pilot Gas Fuel Flow Meter: ☐ Yes ☐ No			

GAS SULFUR TREATMENT (if applicable)

Sulfur Treatment System	Type of system (submit manufacturer's documentation):
	Control Efficiency:_____ %, Source:
	Outlet sulfur concentration: _____ ppmw or gr-S/100 scf, Source:

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and 40 hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed flare location to the nearest property line of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the flare to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed flare location to the nearest property line of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the flare to the receptor, i.e. North or Southwest.
Exhaust Parameters	Release Height	250 feet above grade	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____ ° from vert. or _____ ° from horiz.	
Exhaust Data	Flowrate: _____ acfm	Temperature: (N/A) °F	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

San Joaquin Valley Unified Air Pollution Control District
Supplemental Application Form

Flares

Please complete one form for each flare.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
FLARE LOCATION (STREET ADDRESS or ¼ SECTION, TOWNSHIP, & RANGE): Section 10 of Township 30 South, Range 24 East in Kern County

PROCESS DESCRIPTION

Process Data	Gas Streams/Processes the Flare Serves (include permit number(s), if applicable): Emergency elevated flare with natural gas pilot primarily serving the Sulfur Recovery Unit.	
	Is the flare gas pressure ≥ 5 psig? ☐ Yes ☒ No	
	Maximum Potential Flare Gas Flowrate: 36 MMBtu/hr acf/hr, _____ acf/day, 5,000 MMBtu/yr acf/year	
	Is this a municipal landfill flare? ☐ Yes ☒ No	Is this an emergency flare? ☒ Yes ☐ No

EQUIPMENT DESCRIPTION

Tip Data	Tip Manufacturer: TBD	Tip Model: TBD
	Serial No.: TBD	Tip Manufacturer's rated capacity: TBD (MMcf/hr)
	Tip Opening Cross Sectional Area: 3.14 (ft2)	
	Is this a ground level flare? ☐ Yes ☒ No	Is this an enclosed flare? ☐ Yes ☒ No
Flare Design and Emission Control Equipment	☐ Air-assist flare, _____ scfm of assist air	
	☐ Steam assist flare, _____ lb/min of assist steam	
	☐ Coanda effect flare	
	☒ Other type of flare (please provide details): Natural Gas Assist (if required)	
	Smokeless Operation? ☒ Yes ☐ No, Source: Supplier's experience	
Flare Emissions Data	NO_X Emission Factor: 0.12 (lb/MMBtu)	
	PM_{10} Emission Factor: 0.003 (lb/MMBtu)	
	CO Emission Factor: 0.08 (lb/MMBtu)	
	VOC Emission Factor: 0.0013 (lb/MMBtu)	
	VOC destruction efficiency: 99 %	
Source of Data	☒ Manufacturer's Specifications ☐ Emissions Source Test ☐ AP-42 ☐ Other _____ **Note: please provide copies of all sources of emissions data.**	

FLARED GAS DATA

Flared Gas Data	Fuel Type:	
	Flare Gas Fuel Flow Meter? ☐ Yes ☒ No	
	Higher Heating Value: 205 Btu/scf	Sulfur Content: _____ gr/100 scf
	Carbon to Hydrogen ratio:	
	Percent weight of hydrocarbons heavier than pentane (please attach gas analysis):	

PILOT EQUIPMENT AND FUEL DATA

Pilot Type	Intermittent ☐	Continuous ☒	Automatic (Flow Sensing) Ignition System ☐	Heat Sensing Ignition System ☐
Pilot Fuel Data	Type of pilot gas fuel (e.g., LPG/propane, methane, or process gas stream): Natural Gas			
	Pilot Fuel Consumption: 0.3 MMBtu/hr (scf/hr)		Sulfur Content: <= 0.75 gr/100 scf	
	Pilot Gas Fuel Flow Meter: ☐ Yes ☐ No			

GAS SULFUR TREATMENT (if applicable)

Sulfur Treatment System	Type of system (submit manufacturer's documentation): caustic scrubber
	Control Efficiency: 99.6 %, Source: Manufacturer
	Outlet sulfur concentration: 18.4 lb/hr ppmw or gr-S/100 scf, Source: based on 99.6% control

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and 40 hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed flare location to the nearest property line of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the flare to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed flare location to the nearest property line of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the flare to the receptor, i.e. North or Southwest.
Exhaust Parameters	Release Height	250 feet above grade	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____ ° from vert. or _____ ° from horiz.	
Exhaust Data	Flowrate: _____ acfm	Temperature: (N/A) °F	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

San Joaquin Valley Air Pollution Control District
Supplemental Application Form

Boilers, Steam Generators, Dryers, and Process Heaters

Please complete one form for each different piece of equipment.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form

PERMIT TO BE ISSUED TO:	Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED:	Section 10 of Township 30 South, Range 24 East in Kern County

EQUIPMENT DESCRIPTION (Tail Gas Thermal Oxidizer)

Equipment Details	☐ Boiler ☐ Steam Generator ☐ Dryer ☐ Process Heater ☐ Refinery Unit ☒ Other: Thermal Oxidizer	
	Manufacturer: TBD	
	Model: TBD	Serial Number: TBD
	Steam: _____ pph, at _____ psig _____ bhp	
	Is this a "Load-Following" unit? ☐ Yes ☒ No (Note: A load following unit is a unit with normal operational load fluctuations and requirements which exceed the operational response range of an Ultra-Low NO_X burner system operating at 9 ppmv NO_X.)	
	☐ Indirect-Fired ☒ Direct-Fired	
	Flue Gas Recirculation: ☐ Forced FGR ☐ Induced FGR ☒ None	
	Is an O_2 Controller present? ☐ No ☐ Yes, Manufacturer:	
Rules 4305/4306 Type of Use and Emissions Monitoring Provisions	☐ Low Use - limited to less than 9 billion Btu/year, must have fuel use meter ☐ Tune the unit at least twice per calendar year in accordance with District Rule 4304 ☐ Operate the unit in a manner that maintains exhaust O_2 concentration ≤ 3.00% by volume on a dry basis ☐ Limited Use - limited from 9 billion Btu/year to 30 billion Btu/year, must have fuel use meter ☒ Full Time - limited from greater than 30 billion Btu/year to full time operation (8,760 hrs/year)	
	Note: Low Use units must identify operational characteristics recommended by the manufacturer, which can be monitored on a monthly basis (please provide details in additional documentation).	
	Note: Limited Use or Full Time units must have either a Continuous Emission Monitoring System (CEMS) or one of the following alternate emissions monitoring plans ☐ CEMS, please specify all pollutants monitored: ☐ NO_x ☐ CO ☐ O_2 ☐ Other: _____ ☐ Monitoring of NO_x, CO, and O_2 concentrations ☐ Periodic determination of flue gas recirculation rate by temperature measurement ☐ Periodic determination of flue gas recirculation rate by O_2 measurement ☐ Monitoring of burner mechanical adjustments and O_2 concentration ☐ Monitoring of the flue gas recirculation valve(s) setting ☐ Other Alternate Monitoring Plan (approved on a case by case basis), attach details	
	Note: See District policy (SSP-1105) for additional details of pre-approved alternate emissions monitoring plans, at: http://www.valleyair.org/policies_per/Policies/SSP 1105.pdf	
Fuel Use Meter	☒ Gaseous Fuel Meter ☐ Liquid Fuel Meter ☐ None	
Primary Burner	Manufacturer: TBD	Type: ☒ Standard ☐ Low NO_x ☐ Ultra Low NO_x
	Model: TBD	Serial Number:
	Maximum Heat Input Rating: 13 normal + 80 startup MMBtu/hr	Annual Heat Input: ____120 billion Btu/year
Secondary Burner (if more than one burner is present)	Manufacturer:	Type: ☐ Standard ☐ Low NO_x ☐ Ultra Low NO_x
	Model:	Serial Number:
	Maximum Heat Input Rating: _____ MMBtu/hr	Annual Heat Input: _____ billion Btu/year

EMISSIONS DATA

Note: See District BACT and District Rules 4305 and 4306 requirements for applicability to proposed unit at http://www.valleyair.org/busind/pto/bact/chapter1.pdf, http://www.valleyair.org/rules/currntrules/r4305.pdf, and http://www.valleyair.org/rules/currntrules/r4306.pdf.

Primary Fuel	Fuel Type: ☒ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or __1,020 Btu/scf			Sulfur Content: __2 lb/hr % by weight or _____ gr/scf		
Primary Fuel Emissions Data	Operational Mode	Steady State (ppmv)	Steady State (lb/MMBtu)	Start-up (ppmv)	Start-up (lb/hr)	Shutdown (ppmv) / Shutdown (lb/hr)
	Nitrogen Oxides		0.24		0.24	
	Carbon Monoxide		0.2		0.2	
	Volatile Organic Compounds		0.006		0.006	
	Duration (please provide justification)			__24 hr/day	__48 hr/yr	_____ hr/day / _____ hr/yr
	% O_2, dry basis, if corrected to other than 3%: _____ %					
Secondary Fuel	Fuel Type: ☐ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf			Sulfur Content: _____ % by weight or _____ gr/scf		
	How will the secondary fuel be used? ☐ Secondary full-time fuel ☐ Backup for primary fuel ☐ Other: _____					
Secondary Fuel Emissions Data	Operational Mode	Steady State (ppmv)	Steady State (lb/MMBtu)	Start-up (ppmv)	Start-up (lb/hr)	Shutdown (ppmv) / Shutdown (lb/hr)
	Nitrogen Oxides					
	Carbon Monoxide					
	Volatile Organic Compounds					
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day / _____ hr/yr
	% O_2, dry basis, if corrected to other than 3%: _____ %					
Source of Data	☒ Manufacturer's Specifications ☐ Emission Source Test ☐ Other _____ (please provide copies)					
Additional Emissions Control Equipment	☐ Selective Catalytic Reduction - Manufacturer: _____ Model: _____ ☐ Ammonia (NH_3) ☐ Urea ☐ Other: _____					
	☐ Non-Selective Catalytic Reduction - Manufacturer: _____ Model: _____					
	Control Efficiencies: NO_x _____ %, SO_x _____ %, PM_{10} _____ %, CO _____ %, VOC _____ %					
	☐ Other (please specify):					

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: __24 hours per day, and _____8,760 hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	__165 feet above grade	
	Stack Diameter	__30 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: __15,000 acfm	Temperature: __1200 °F	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

FOR DISTRICT USE ONLY

Date:	**FID:**	**Project:**	**Public Notice: [ ] Yes [ ] No**
Comments:			

San Joaquin Valley Air Pollution Control District
Supplemental Application Form

Emergency/Low-Use IC Engines for Non-Agricultural Operations

Please complete one form for each engine.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

EQUIPMENT DESCRIPTION: Emergency Generator 1

Engine Details	Engine Manufacturer: Cummins		Number of Cylinders:
	Engine Model: QSK60-G6		Engine Year of Manufacture: TBD
	Engine Serial Number: TBD		Engine Tier Rating: 4
	Engine Certification Family Number: TBD		
	Engine's Type of Combustion: ☐ Rich-Burn ☐ Lean-Burn ☒ 4-Stroke ☐ 2-Stroke		
	Engine Manufacturer's Maximum Rated Power Output (per the data plate): 2,922 bhp		
	Engine's Rated Power Output for the Process the Engine Serves: _____ bhp		
Process Data	Process the Engine Serves:		
	Electrical Power Generation Only	Generator Manufacturer: Cummins	Model: DQKC
		Power Output: 2,000 kW	
	Will this equipment be used in an electric utility rate reduction program? ☐ Yes ☒ No		
Fuel Data	Fuel Type: ☒ Diesel ☐ Natural Gas ☐ LPG/Propane ☐ Gasoline ☐ Other: _____		
	For "Other" fuels only: Higher Heating Value: _____ Btu/scf, or _____ Btu/gal, For "Other" fuels only: An Ultimate Fuel Analysis or the combustion F-Factor _____dscf/MMBtu		
	Sulfur Content: _____ gr/100 scf (gaseous fuel) or 15 ppm by weight (liquid fuel)		
	Fuel Consumption at Maximum Rated Output: 140 gal/hr, or _____ scf/hr		
Rule 4702 Type of Use	☒ Emergency Standby - Limited exclusively to power primary mechanical or an electrical generator during periods of unscheduled power outages beyond the control of the operator, and limited from 20 to 100 hrs/yr (depending on the engine's PM_{10} emission factor) for maintenance and testing purposes only. ☐ This engine is specifically used to power a pump for a municipal water supply. ☐ I request the higher opacity limit of 40% with the corresponding operational limits of 30 minutes per week and 2 hours per month for maintenance and testing. (CH&SC 41701.6) ☐ I request the lower opacity limit of 20%. ☐ This engine is specifically used to provide power at a health care facility. (CH&SC 1250) ☐ This engine is subject to Office of Statewide Health Planning and Development (OSHPD) requirements. ☐ Special Case Emergency - Limited exclusively to preserve or protect property, human life, or public health during a disaster or a state emergency (e.g. fire or flood) and limited to 20 to 100 hrs/yr (depending on the engine's PM_{10} emission factor) for maintenance and testing purposes only. ☐ This engine is specifically used to power a direct-drive firewater pump. ☐ This firewater pump engine is subject to National Fire Protection Association (NFPA) requirements. ☐ Low Use - Limited to ≤ 200 hrs/yr of operation for **ALL** purposes combined, including maintenance and testing.		
Hour Meter	Note: All engines are required to have either a nonresettable elapsed time meter or an alternate device, method, or technique, approved by the APCO, for determining elapsed operating time. ☒ Equipped with a Nonresettable Elapsed Operating Time Meter ☐ Alternate Method (please provide details): _____		

EMISSIONS CONTROL

Emissions Control Equipment (Check all that apply)	☐ Positive Crankcase Ventilation System	☐ 90% Efficient crankcase emission control device
	☐ Turbocharger	☐ Intercooler/Aftercooler
	☐ Automatic Air/Fuel Ratio or O_2 Controller - Manufacturer: _____	
	☐ Non-Selective Catalytic Reduction: Manufacturer: _____ Model: _____ Control Efficiencies: NO_X _____ %, SO_X _____ %, PM_{10} _____ %, CO _____ %, VOC _____ %	
	☐ Particulate Filter - Manufacturer: _____ Model: _____ Control Efficiency: _____ %	
	☐ Other (please specify):	

EMISSIONS DATA

Note: See District BACT and District Rule 4702 requirements for applicability to proposed engine at http://www.valleyair.org/busind/pto/bact/chapter3.pdf and http://www.valleyair.org/rules/currntrules/r4702.pdf.

	Pollutant	(g/bhp-hr)	(g/kW-hr)	(ppmvd)
Emissions Data	Nitrogen Oxides (NO_x)	0.50		
	Volatile Organic Compounds (VOC)	0.30		
	NO_x + NMHC			
	Particulate Matter (PM_{10})	0.07		
	Carbon Monoxide	2.60		
	% O_2, dry basis, if corrected to other than 15%: _____ %			
Source of Data	☒ Manufacturer's Specifications ☐ Emissions Source Test ☐ CARB/EPA Certification ☒ Other _USEPA Tier 4 standards for 2011 model equipment **Note: please provide copies of all sources of emissions data.**			

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: _1_____ hours per day, and _50_____ hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	_20_____ feet above grade	
	Stack Diameter	_14_____ inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☐ None ☐ Other: _____	
	Direction of Flow	☐ Vertically Upward ☐ Horizontal ☐ Other: _____ ° from vert. or _____ ° from horiz.	
Exhaust Data	Flowrate: _15000_____ acfm	Temperature: _760_____ °F	
Transportable	Is this engine transportable? ☐ Yes ☒ No Note: This is used for health risk assessment purposes only.		
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

San Joaquin Valley Air Pollution Control District
Supplemental Application Form

Emergency/Low-Use IC Engines for Non-Agricultural Operations

Please complete one form for each engine.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

EQUIPMENT DESCRIPTION: Emergency Generator 2

Engine Details	Engine Manufacturer: Cummins		Number of Cylinders:
	Engine Model: QSK60-G6		Engine Year of Manufacture: TBD
	Engine Serial Number: TBD		Engine Tier Rating: 4
	Engine Certification Family Number: TBD		
	Engine's Type of Combustion: ☐ Rich-Burn ☐ Lean-Burn ☒ 4-Stroke ☐ 2-Stroke		
	Engine Manufacturer's Maximum Rated Power Output (per the data plate): 2,922 bhp		
	Engine's Rated Power Output for the Process the Engine Serves: _____ bhp		
Process Data	Process the Engine Serves:		
	Electrical Power Generation Only	Generator Manufacturer: Cummins	Model: DQKC
		Power Output: 2,000 kW	
	Will this equipment be used in an electric utility rate reduction program? ☐ Yes ☒ No		
Fuel Data	Fuel Type: ☒ Diesel ☐ Natural Gas ☐ LPG/Propane ☐ Gasoline ☐ Other: _____		
	For "Other" fuels only: Higher Heating Value: _____ Btu/scf, or _____ Btu/gal, For "Other" fuels only: An Ultimate Fuel Analysis or the combustion F-Factor _____dscf/MMBtu		
	Sulfur Content: _____ gr/100 scf (gaseous fuel) or 15 ppm by weight (liquid fuel)		
	Fuel Consumption at Maximum Rated Output: 140 gal/hr, or _____ scf/hr		
Rule 4702 Type of Use	☒ Emergency Standby - Limited exclusively to power primary mechanical or an electrical generator during periods of unscheduled power outages beyond the control of the operator, and limited from 20 to 100 hrs/yr (depending on the engine's PM_{10} emission factor) for maintenance and testing purposes only. ☐ This engine is specifically used to power a pump for a municipal water supply. ☐ I request the higher opacity limit of 40% with the corresponding operational limits of 30 minutes per week and 2 hours per month for maintenance and testing. (CH&SC 41701.6) ☐ I request the lower opacity limit of 20%. ☐ This engine is specifically used to provide power at a health care facility. (CH&SC 1250) ☐ This engine is subject to Office of Statewide Health Planning and Development (OSHPD) requirements. ☐ Special Case Emergency - Limited exclusively to preserve or protect property, human life, or public health during a disaster or a state emergency (e.g. fire or flood) and limited to 20 to 100 hrs/yr (depending on the engine's PM_{10} emission factor) for maintenance and testing purposes only. ☐ This engine is specifically used to power a direct-drive firewater pump. ☐ This firewater pump engine is subject to National Fire Protection Association (NFPA) requirements. ☐ Low Use - Limited to ≤ 200 hrs/yr of operation for **ALL** purposes combined, including maintenance and testing.		
Hour Meter	Note: All engines are required to have either a nonresettable elapsed time meter or an alternate device, method, or technique, approved by the APCO, for determining elapsed operating time. ☒ Equipped with a Nonresettable Elapsed Operating Time Meter ☐ Alternate Method (please provide details): _____		

EMISSIONS CONTROL

Emissions Control Equipment (Check all that apply)	☐ Positive Crankcase Ventilation System	☐ 90% Efficient crankcase emission control device
	☐ Turbocharger	☐ Intercooler/Aftercooler
	☐ Automatic Air/Fuel Ratio or O_2 Controller - Manufacturer: _____	
	☐ Non-Selective Catalytic Reduction: Manufacturer: _____ Model: _____ Control Efficiencies: NO_X _____ %, SO_X _____ %, PM_{10} _____ %, CO _____ %, VOC _____ %	
	☐ Particulate Filter - Manufacturer: _____ Model: _____ Control Efficiency: _____ %	
	☐ Other (please specify):	

EMISSIONS DATA

Note: See District BACT and District Rule 4702 requirements for applicability to proposed engine at http://www.valleyair.org/busind/pto/bact/chapter3.pdf and http://www.valleyair.org/rules/currntrules/r4702.pdf.

	Pollutant	(g/bhp-hr)	(g/kW-hr)	(ppmvd)
Emissions Data	Nitrogen Oxides (NO_x)	0.50		
	Volatile Organic Compounds (VOC)	0.30		
	NO_x + NMHC			
	Particulate Matter (PM_{10})	0.07		
	Carbon Monoxide	2.60		
	% O_2, dry basis, if corrected to other than 15%: _____ %			
Source of Data	☒ Manufacturer's Specifications ☐ Emissions Source Test ☐ CARB/EPA Certification ☒ Other _USEPA Tier 4 standards for 2011 model equipment **Note: please provide copies of all sources of emissions data.**			

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: _1_____ hours per day, and _50_____ hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	_20_____ feet above grade	
	Stack Diameter	_14_____ inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☐ None ☐ Other: _____	
	Direction of Flow	☐ Vertically Upward ☐ Horizontal ☐ Other: _____ ° from vert. or _____ ° from horiz.	
Exhaust Data	Flowrate: _15000_____ acfm	Temperature: _760_____ °F	
Transportable	Is this engine transportable? ☐ Yes ☒ No Note: This is used for health risk assessment purposes only.		
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

San Joaquin Valley Air Pollution Control District
Supplemental Application Form

Emergency/Low-Use IC Engines for Non-Agricultural Operations

Please complete one form for each engine.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

EQUIPMENT DESCRIPTION: Emergency Fire Water Pump Engine

Engine Details	Engine Manufacturer: Cummins		Number of Cylinders:
	Engine Model: CFP-15E-F40		Engine Year of Manufacture: TBD
	Engine Serial Number: TBD		Engine Tier Rating: 4
	Engine Certification Family Number: TBD		
	Engine's Type of Combustion: ☐ Rich-Burn ☐ Lean-Burn ☒ 4-Stroke ☐ 2-Stroke		
	Engine Manufacturer's Maximum Rated Power Output (per the data plate): 556 bhp		
	Engine's Rated Power Output for the Process the Engine Serves: _____ bhp		
Process Data	Process the Engine Serves: Standby Firewater Pump		
	Electrical Power Generation Only	Generator Manufacturer:	Model:
		Power Output: _____ kW	
	Will this equipment be used in an electric utility rate reduction program? ☐ Yes ☒ No		
Fuel Data	Fuel Type: ☒ Diesel ☐ Natural Gas ☐ LPG/Propane ☐ Gasoline ☐ Other: _____		
	For "Other" fuels only: Higher Heating Value: _____ Btu/scf, or _____ Btu/gal, For "Other" fuels only: An Ultimate Fuel Analysis or the combustion F-Factor _____dscf/MMBtu		
	Sulfur Content: _____ gr/100 scf (gaseous fuel) or 15 ppm by weight (liquid fuel)		
	Fuel Consumption at Maximum Rated Output: 28 gal/hr, or _____ scf/hr		
Rule 4702 Type of Use	☒ Emergency Standby - Limited exclusively to power primary mechanical or an electrical generator during periods of unscheduled power outages beyond the control of the operator, and limited from 20 to 100 hrs/yr (depending on the engine's PM_{10} emission factor) for maintenance and testing purposes only. ☒ This engine is specifically used to power a pump for a municipal water supply. ☐ I request the higher opacity limit of 40% with the corresponding operational limits of 30 minutes per week and 2 hours per month for maintenance and testing. (CH&SC 41701.6) ☐ I request the lower opacity limit of 20%. ☐ This engine is specifically used to provide power at a health care facility. (CH&SC 1250) ☐ This engine is subject to Office of Statewide Health Planning and Development (OSHPD) requirements. ☐ Special Case Emergency - Limited exclusively to preserve or protect property, human life, or public health during a disaster or a state emergency (e.g. fire or flood) and limited to 20 to 100 hrs/yr (depending on the engine's PM_{10} emission factor) for maintenance and testing purposes only. ☐ This engine is specifically used to power a direct-drive firewater pump. ☐ This firewater pump engine is subject to National Fire Protection Association (NFPA) requirements. ☐ Low Use - Limited to ≤ 200 hrs/yr of operation for **ALL** purposes combined, including maintenance and testing.		
Hour Meter	Note: All engines are required to have either a nonresettable elapsed time meter or an alternate device, method, or technique, approved by the APCO, for determining elapsed operating time. ☐ Equipped with a Nonresettable Elapsed Operating Time Meter ☒ Alternate Method (please provide details): TBD		

EMISSIONS CONTROL

Emissions Control Equipment (Check all that apply)	☐ Positive Crankcase Ventilation System	☐ 90% Efficient crankcase emission control device
	☐ Turbocharger	☐ Intercooler/Aftercooler
	☐ Automatic Air/Fuel Ratio or O_2 Controller - Manufacturer: _____	
	☐ Non-Selective Catalytic Reduction: Manufacturer: _____ Model: _____ Control Efficiencies: NO_X _____ %, SO_X _____ %, PM_{10} _____ %, CO _____ %, VOC _____ %	
	☐ Particulate Filter - Manufacturer: _____ Model: _____ Control Efficiency: _____ %	
	☐ Other (please specify):	

EMISSIONS DATA

Note: See District BACT and District Rule 4702 requirements for applicability to proposed engine at http://www.valleyair.org/busind/pto/bact/chapter3.pdf and http://www.valleyair.org/rules/currntrules/r4702.pdf.

	Pollutant	(g/bhp-hr)	(g/kW-hr)	(ppmvd)
Emissions Data	Nitrogen Oxides (NO_x)	1.50		
	Volatile Organic Compounds (VOC)	0.14		
	NO_x + NMHC			
	Particulate Matter (PM_{10})	0.015		
	Carbon Monoxide	2.60		
	% O_2, dry basis, if corrected to other than 15%: _____ %			
Source of Data	☒ Manufacturer's Specifications ☐ Emissions Source Test ☐ CARB/EPA Certification ☒ Other _USEPA Tier 4 standards for 2011 model equipment **Note: please provide copies of all sources of emissions data.**			

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 2 hours per day, and 50 hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	20 feet above grade	
	Stack Diameter	8 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☐ None ☐ Other: _____	
	Direction of Flow	☐ Vertically Upward ☐ Horizontal ☐ Other: _____ ° from vert. or _____ ° from horiz.	
Exhaust Data	Flowrate: 3600 acfm	Temperature: 850 °F	
Transportable	Is this engine transportable? ☐ Yes ☒ No Note: This is used for health risk assessment purposes only.		
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

San Joaquin Valley Air Pollution Control District
Supplemental Application Form

Boilers, Steam Generators, Dryers, and Process Heaters

Please complete one form for each different piece of equipment.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC	
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County	

EQUIPMENT DESCRIPTION (Ammonia Plant Startup Heater)

Equipment Details	☐ Boiler ☐ Steam Generator ☐ Dryer ☒ Process Heater ☐ Refinery Unit ☐ Other: _____	
	Manufacturer: TBD	
	Model: TBD	Serial Number: TBD
	Steam: _____ pph, at _____ psig _____ bhp	
	Is this a "Load-Following" unit? ☐ Yes ☒ No (Note: A load following unit is a unit with normal operational load fluctuations and requirements which exceed the operational response range of an Ultra-Low NO_X burner system operating at 9 ppmv NO_X.)	
	☐ Indirect-Fired ☒ Direct-Fired	
	Flue Gas Recirculation: ☐ Forced FGR ☐ Induced FGR ☐ None	
	Is an O_2 Controller present? ☐ No ☐ Yes, Manufacturer:	
Rules 4305/4306 Type of Use and Emissions Monitoring Provisions	☒ Low Use - limited to less than 9 billion Btu/year, must have fuel use meter ☐ Tune the unit at least twice per calendar year in accordance with District Rule 4304 ☐ Operate the unit in a manner that maintains exhaust O_2 concentration ≤ 3.00% by volume on a dry basis ☐ Limited Use - limited from 9 billion Btu/year to 30 billion Btu/year, must have fuel use meter ☐ Full Time - limited from greater than 30 billion Btu/year to full time operation (8,760 hrs/year)	
	Note: Low Use units must identify operational characteristics recommended by the manufacturer, which can be monitored on a monthly basis (please provide details in additional documentation).	
	Note: Limited Use or Full Time units must have either a Continuous Emission Monitoring System (CEMS) or one of the following alternate emissions monitoring plans ☐ CEMS, please specify all pollutants monitored: ☐ NO_x ☐ CO ☐ O_2 ☐ Other: _____ ☐ Monitoring of NO_x, CO, and O_2 concentrations ☐ Periodic determination of flue gas recirculation rate by temperature measurement ☐ Periodic determination of flue gas recirculation rate by O_2 measurement ☐ Monitoring of burner mechanical adjustments and O_2 concentration ☐ Monitoring of the flue gas recirculation valve(s) setting ☐ Other Alternate Monitoring Plan (approved on a case by case basis), attach details	
	Note: See District policy (SSP-1105) for additional details of pre-approved alternate emissions monitoring plans, at: http://www.valleyair.org/policies_per/Policies/SSP 1105.pdf	
Fuel Use Meter	☒ Gaseous Fuel Meter ☐ Liquid Fuel Meter ☐ None	
Primary Burner	Manufacturer: TBD	Type: ☐ Standard ☒ Low NO_x ☐ Ultra Low NO_x
	Model: TBD	Serial Number: TBD
	Maximum Heat Input Rating: ____55 MMBtu/hr	Annual Heat Input: ____7.7 billion Btu/year
Secondary Burner (if more than one burner is present)	Manufacturer:	Type: ☐ Standard ☐ Low NO_x ☐ Ultra Low NO_x
	Model:	Serial Number:
	Maximum Heat Input Rating: _____ MMBtu/hr	Annual Heat Input: _____ billion Btu/year

EMISSIONS DATA

Note: See District BACT and District Rules 4305 and 4306 requirements for applicability to proposed unit at http://www.valleyair.org/busind/pto/bact/chapter1.pdf, http://www.valleyair.org/rules/currntrules/r4305.pdf, and http://www.valleyair.org/rules/currntrules/r4306.pdf.

Primary Fuel	Fuel Type: ☒ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or __1,020 Btu/scf			Sulfur Content: __<12.65 ppmv % by weight or _____		
Primary Fuel Emissions Data	Operational Mode	Steady State (ppmv)	Steady State (lb/MMBtu)	Start-up (ppmv)	Start-up (lb/hr)	Shutdown (ppmv)	Shutdown (lb/hr)
	Nitrogen Oxides	9	0.011				
	Carbon Monoxide	50	0.037				
	Volatile Organic Compounds		0.004				
	Duration (please provide justification)			_ hr/day	_ hr/yr	_____ hr/day	_____ hr/yr
	% O_2, dry basis, if corrected to other than 3%: ___ %						
Secondary Fuel	Fuel Type: ☐ Natural Gas ☐ LPG/Propane ☐ Diesel ☐ Other: _____					
	Higher Heating Value: _____ Btu/gal or _____ Btu/scf			Sulfur Content: _____ % by weight or _____ gr/scf		
	How will the secondary fuel be used? ☐ Secondary full-time fuel ☐ Backup for primary fuel ☐ Other: _____					
Secondary Fuel Emissions Data	Operational Mode	Steady State (ppmv)	Steady State (lb/MMBtu)	Start-up (ppmv)	Start-up (lb/hr)	Shutdown (ppmv)	Shutdown (lb/hr)
	Nitrogen Oxides						
	Carbon Monoxide						
	Volatile Organic Compounds						
	Duration (please provide justification)			_____ hr/day	_____ hr/yr	_____ hr/day	_____ hr/yr
	% O_2, dry basis, if corrected to other than 3%: _____ %						
Source of Data	☒ Manufacturer's Specifications ☐ Emission Source Test ☐ Other _____ (please provide copies)					
Additional Emissions Control Equipment	☐ Selective Catalytic Reduction - Manufacturer: _____ Model: _____ ☐ Ammonia (NH_3) ☐ Urea ☐ Other: _____					
	☐ Non-Selective Catalytic Reduction - Manufacturer: _____ Model: _____					
	Control Efficiencies: NO_x _____ %, SO_x _____ %, PM_{10} _____ %, CO _____ %, VOC _____ %					
	☐ Other (please specify):					

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: ___24 hours per day, and _____140 hours per year		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___80 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___10,800 acfm	Temperature: __300 °F	
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

FOR DISTRICT USE ONLY

Date:	**FID:**	**Project:**	**Public Notice: [ ] Yes [ ] No**
Comments:			

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Urea Pastillation Unit Baghouse)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:__TBD_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Urea Pastillation Unit
Type of material collected by the baghouse/dust collector: Urea dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,720_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Urea Pastillation Unit	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: ___24 hours per day, and _____8,052_____ hours per year		
	☐ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___50 feet above grade	
	Stack Diameter	___18 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___6,660 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Unified Air Pollution Control District
Supplemental Application Form

Scrubbers

Please complete one form for each scrubber.

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

PROCESS DESCRIPTION (Ammonium Nitrate Unit)

Process Data	Gas Streams/Processes the Scrubber Serves (include permit number(s) and/or process flow diagrams, if applicable): Ammonium Nitrate Unit	
	Maximum Gas Flowrate: 170_____ acfm	Expected Gas Flowrate: 160_____ acfm

EQUIPMENT DESCRIPTION

Equipment	Manufacturer: TBD_____	Model:TBD_____	Serial No.:TBD_____	
Scrubber Type	☐ Dry Scrubber			
	☒ Wet Scrubber Select Type(s) of Wet Scrubber	☐ Packed Bed	☐ Orifice	☒ Condensation Scrubbing
		☐ Tray/Plate	☐ Spray Chamber	☐ Venturi
	☐ Other type of scrubber (please provide details):_____			
	Configuration: ☒ Vertical ☐ Horizontal		Flow Type: ☐ Concurrent ☐ Counter-Current	
Dimensions	Height:_____ ft. Diameter: _____ ft. Length: _____ ft.			
Purpose (To Remove)	☐ Odor (type):_____		☐ SO_X:_____	
	☐ VOC (type):_____		☐ H_2S:_____	
	☒ Particulates (type):_ammonium nitrate____		☐ Inorganic Fumes and Gases (type):_____	
	☐ Other:_____			

	Packed Bed	**Venturi**
Components	Type of Packing Material: Packed column with demister at outlet_____	Throat Diameter:_____ in.
	Manufacturer:_____	Throat Length:_____ in.
	Packing Factor:_____	Pressure Drop Across Throat: _____in. of water
	Packing Size:_____	Throat Velocity:_____ ft./min
	Height of Packing Material:_____ft.	Drop Diameter:_____ microns
	Operating Pressure Range (all scrubber types): _____ - _____ psi	

EQUIPMENT DESCRIPTION (continued)

Scrubbing Liquid Medium	Scrubbing Liquor		Temperature: 120 °F
	Composition	Weight %	Blow-Down Rate: 34 gpm
	Water		Make-up Rate: ____ gpm
	Ammonium nitrate	0.6	Recirculation Rate: 430 gpm
			Flow Meter(s) Present? ☐ Yes ☐ No
	Scrubbing Solution: ☐ Once Through ☐ Recirculated		Total Pump H.P.: ____
	pH of Scrubbing Medium (range): ____ - ____		pH Meter Present? ☐ Yes ☐ No
	ORP of Scrubbing Medium (range): ____ - ____ millivolts		ORP Meter Present? ☐ Yes ☐ No

EMISSIONS DATA

	Pollutant	ppmvd	lb/hr	Control Efficiency (%)	Source of Data
Emissions Data	Nitrogen Oxides (NO_2)				☒ Manufacturer's Specifications
	Particulate Matter (PM_{10})		0.2		☐ Emissions Source Test
	Carbon Monoxide				☐ AP-42; Section: ____
	Volatile Organic Compounds				☐ Other: ____
	Sulfur Dioxide (SO_2)				Note: please provide copies of all sources of emissions data
	Hydrogen Sulfide (H_2S)				

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and 8,000 hours per year		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	40 feet above grade	
	Stack Diameter	2 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: ____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: ____ ° from vert. or ____ ° from horiz.	
Exhaust Data	Flowrate: 18 acfm	Temperature: 100 °F	Blower H.P.: ____
Facility Location	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Coal Rail Unloading Station)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System - Coal Rail Unloading Station
Type of material collected by the baghouse/dust collector: coal dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____6,107_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Coal Rail Unloading Station	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and 8,760 hours per year Maximum annual capacity factor of 24%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	30 feet above grade	
	Stack Diameter	36 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: 20,000 acfm	Temperature: ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Coal Transfer Tower)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Coal Transfer Tower
Type of material collected by the baghouse/dust collector: coal dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____6,107_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Coal Transfer Tower	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 50%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___100 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___1,500 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Coke Truck Unloading Station)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Coke Truck Unloading Station
Type of material collected by the baghouse/dust collector: petcoke dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,368_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Coke Truck Unloading Station	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 36%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___60 feet above grade	
	Stack Diameter	___72 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___80,000 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Coal/Coke Transfer Tower B)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Coal/Coke Transfer Tower B
Type of material collected by the baghouse/dust collector: coal and petcoke dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____7,475_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Coal/Coke Transfer Tower B	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 36%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___100 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___1,500 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Coal/Coke Crusher Building)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Coal/Coke Crusher Building
Type of material collected by the baghouse/dust collector: coal and petcoke dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____7,475_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Coal/Coke Crusher Building	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 50%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___100 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___1,500 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Urea Bucket Elevator to Conveyor)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Urea Bucket Elevator to Conveyor
Type of material collected by the baghouse/dust collector: urea dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,720_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Urea Bucket Elevator to Conveyor	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	_____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___50 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___1,500 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Urea Transfer Tower 1)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Urea Transfer Tower 1
Type of material collected by the baghouse/dust collector: urea dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,720_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

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EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Urea Transfer Tower 1	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___100 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___1,500 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Urea Transfer Tower 2)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Urea Transfer Tower 2
Type of material collected by the baghouse/dust collector: urea dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,720_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Urea Transfer Tower 2	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 25%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___100 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___1,500 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Urea Transfer Tower 3)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Urea Transfer Tower 3
Type of material collected by the baghouse/dust collector: urea dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,720_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Urea Transfer Tower 3	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 50%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___100 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___1,500 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Urea Transfer Tower 4)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Urea Transfer Tower 4
Type of material collected by the baghouse/dust collector: urea dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,720_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Urea Transfer Tower 4	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 25%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___100 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___1,500 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Urea Transfer Tower 5)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Urea Transfer Tower 5
Type of material collected by the baghouse/dust collector: urea dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,720_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Urea Transfer Tower 5	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 24%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___100 feet above grade	
	Stack Diameter	___10 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___1,500 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Urea Loading Building Baghouse 1)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Urea Loading Building Baghouse 1
Type of material collected by the baghouse/dust collector: urea dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,720_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Urea Loading Building Baghouse 1	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 24%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___30 feet above grade	
	Stack Diameter	___36 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___20,000 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Urea Loading Building Baghouse 2)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Urea Loading Building Baghouse 2
Type of material collected by the baghouse/dust collector: urea dust
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,720_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Urea Loading Building Baghouse 2	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 24%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___30 feet above grade	
	Stack Diameter	___24 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___10,000 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Gasification Solids Transfer Tower)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Gasification Solids Transfer Tower
Type of material collected by the baghouse/dust collector: gasification solids
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,678_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Gasification Solids Transfer Tower	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 15%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___30 feet above grade	
	Stack Diameter	___14 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___3,000 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

San Joaquin Valley Air Pollution Control District

Supplemental Application Form

PROCESSES SERVED BY A BAGHOUSE/DUST COLLECTOR

This form must be accompanied by a completed Application for Authority to Construct and Permit to Operate form.

PERMIT TO BE ISSUED TO: Hydrogen Energy California LLC
LOCATION WHERE THE EQUIPMENT WILL BE OPERATED: Section 10 of Township 30 South, Range 24 East in Kern County

BAGHOUSE/DUST COLLECTOR DESCRIPTION (Gasification Solids Load-Out System)

Baghouse/Dust Collector Data	Manufacturer: TBD	
	Model No.: TBD	Serial No.: TBD
	PM_{10} Control Efficiency: (%) (if available from the manufacturers guarantee)	
	Exhaust PM_{10} Emission Concentration(gr/dscf): 0.001 (if available from the manufacturers guarantee)	
	Differential Pressure Gage [ ] Yes [ ] No	Manufacturer's Recommended Differential Pressure Operating Range: _____ to _____ inches W.C.
Filter Data	Type: [x] Bag/Tube [ ] Cartridge [ ] Envelope [ ] HEPA/Flat [ ] Sock Filter [ ] Other:_____	
	Fabric: [ ] Cotton [ ] Polypropylene [ ] Polyester [ ] Fiberglass [ ] Nomex [ ] Teflon [x] Other:_____	
	Number of Bags/Filters:	Total Cloth Area: (sq. ft.)
	Diameter or Width of Bag/Filter: (in.)	Length of Bag/Filter: (in.)
	Filter Cleaning Method: [ ] Mechanical Shaker [ ] Reverse Air Flow [ ] Pulse Jet	
Blower/Fan Data	Manufacturer:	Model No.
	Power Rating: (Horsepower)	Air Flow Rate: (dscfm)

PROCESS INFORMATION

Process served by baghouse/duct collector: Feedstock Handling System – Gasification Solids Load-Out System
Type of material collected by the baghouse/dust collector: gasification solids
Maximum quantity of material collected by the baghouse/dust collector: _____lb/day
Maximum process weight for operation served by the baghouse/dust collector: _____1,678_____tons/day
Please note, each permit is required by District Rule 2201 to have a daily emission limit (DEL). The information provided above for maximum process rate and operating schedule may be used as an enforceable limiting condition for each Authority to Construct or Permit to Operate that will be issued for the proposed project.

Please Continue on Reverse Side

EQUIPMENT SERVED BY THE BAGHOUSE/DUST COLLECTOR

Description Indicate the type of equipment that will be served by the baghouse/dust collector, such as: Rip saw, drill, router, hammermill, grain cleaner, storage bin, etc. (attach additional sheets if needed.	**Manufacturer**	**Model No.**	**Power Rating (Horsepower) or Storage Capacity (Cubic Feet)** Indicate the horsepower rating if the equipment is powered by an electric motor or indicate the maximum storage capacity if the equipment is a storage bin/silo.
Gasification Solids Load-Out System	TBD	TBD	NA

HEALTH RISK ASSESSMENT DATA

Operating Hours	Maximum Operating Schedule: 24 hours per day, and _____8,760 hours per year Maximum annual capacity factor of 15%		
	☒ Outdoors ☐ Indoors (if indoors, see note 1)		
Receptor Data	Distance to nearest Residence	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest apartment, house, dormitory, etc.
	Direction to nearest Residence	_____	Direction from the stack to the receptor, i.e. Northeast or South.
	Distance to nearest Business	____ feet	Distance is measured from the proposed stack location to the nearest boundary of the nearest office building, factory, store, etc.
	Direction to nearest Business	_____	Direction from the stack to the receptor, i.e. North or Southwest.
Stack Parameters	Release Height	___30 feet above grade	
	Stack Diameter	___24 inches at point of release	
	Rain Cap	☐ Flapper-type ☐ Fixed-type ☒ None ☐ Other: _____	
	Direction of Flow	☒ Vertically Upward ☐ Horizontal ☐ Other: _____° from vert. or _____° from horiz.	
Exhaust Data	Flowrate: ___10,000 acfm	Temperature: __ambient °F	
Facility	☐ Urban (area of dense population) ☒ Rural (area of sparse population)		

Note 1: If baghouse is located inside a building, attach a dimensioned building plan indicating building height, floorplan with dimensions, location of the baghouse plus the height and location/dimension of all doors, windows or ventilation openings which remain open during operation. The plan shall include an arrow indicating the direction of True North. If the building is equipped with a forced air ventilation system, identify all vent locations and fan capacities in CFM.

Appendix B

Criteria Pollutant BACT Analysis

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

HYDROGEN ENERGY CALIFORNIA PROJECT
KERN COUNTY, CALIFORNIA

Prepared For:

San Joaquin Valley Air Pollution Control District
California Energy Commission
U.S. Environmental Protection Agency Region IX

Prepared on behalf of

Hydrogen Energy California LLC

May 2012

URS

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1.0 APPLICABLE REGULATIONS

Federal requirements pertaining to control of pollutants subject to PSD review (i.e., attainment pollutants) were promulgated by the U.S. Environmental Protection Agency (USEPA) in 40 Code of Federal Regulations (CFR) 42.21 (j). This regulation defines Best Available Control Technology (BACT) as emission limits "based on the maximum degree of reduction for each pollutant." BACT determinations are made on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs.

Federal requirements pertaining to control of non-attainment pollutants, or Lowest Achievable Emission Rate (LAER), were promulgated by USEPA under 40 CFR 51.165 (a). This regulation defines LAER as the emissions limit based on either (1) the most stringent emission rate contained in a State Implementation Plan (SIP), unless the [source] demonstrates the rate is not achievable; or (2) the most stringent emissions limitation that is achieved in practice. The federal LAER does not consider the cost impacts of control.

BACT must be applied to any new or modified source resulting in an emissions increase exceeding any San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT threshold. SJVAPCD Rule 2201 requires HECA to apply BACT to any source that has an increase in emissions of oxides of nitrogen (NO_X), volatile organic compounds (VOC), sulfur dioxide (SO_2), carbon monoxide (CO), and particulate matter equal to or less than 10 microns in diameter (PM_{10}) (criteria pollutants) in excess of 2.0 pounds per highest day. BACT for the applicable pollutants was determined by reviewing the SJVAPCD BACT Guidelines Manual, USEPA's BACT/LAER Clearinghouse, the most recent Compilation of California BACT Determinations, CAPCOA (2nd Ed., November 1993), and the South Coast Air Quality Management District BACT Guidelines Manual.

SJVAPCD defines BACT to be the most stringent emission limitation or control technique of the following:

- Achieved in practice for such category and class of source;
- Contained in any State Implementation Plan approved by the U.S. EPA for such category and class of source. A specific limitation or control technique shall not apply if the owner of the proposed emissions unit demonstrates to the satisfaction of the Air Pollution Control Officer (APCO) that such a limitation or control technique is not presently achievable; or
- Contained in an applicable federal New Source Performance Standard; or
- Any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the APCO to be cost effective and technologically feasible for such class or category of sources or for a specific source.

This analysis provides a BACT review for the proposed HECA Project emission sources of NO_X, CO, VOC, PM_{10} and SO_2.

The Combined Cycle Power Block will generate approximately 405 megawatts (MW) of gross power and will provide a nominal 300 MW of low-carbon baseload electricity to the grid during

operations. The basis for the emissions-related analyses is annual average operation at a design capacity of approximately 405 MW of gross power. The Manufacturing Complex is designed for annual production of approximately 1 million tons of nitrogen-based product. The proposed Project as currently configured will involve the following major processes and emission units that require BACT review for the above-mentioned criteria pollutants:

- One hydrogen-rich fuel and/or natural gas–fired Combustion Turbine Generator (CTG) with Heat Recovery Steam Generator (HRSG) and one Steam Turbine-Generator (STG)
- One Multi-cell, Mechanical-draft Cooling Tower for the Combined-Cycle Power Block
- One Multi-cell, Mechanical-draft Cooling Tower for the Air Separation Unit
- One Multi-cell, Mechanical-draft Cooling Tower for the Gasification Block
- One Auxiliary Boiler
- Solid Feedstock Receiving and Handling System
- Gasification Block, including an Elevated Gasification Flare
- Coal Dryer
- Sulfur Recovery System (Tail Gas Thermal Oxidizer and two elevated flares with natural gas assist)
- Two Emergency, Diesel-Engine Generators
- One Diesel-Engine Fire-water Pump
- One carbon dioxide (CO_2) vent stack
- Ammonia Synthesis Unit preheater
- Urea Unit – Absorber Stacks and Pastillation Unit
- Nitric Acid Unit
- Ammonium Nitrate Unit
- Fugitive emissions

Section 2 of the CEC AFC Amendment provides a complete description of the Project indicating the layout of the major components within the site, and general discussion of the Project components.

2.0 BACT REVIEW PROCESS

BACT is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs" [40 CFR 52.21(b)(12)].*

In a December 1, 1987 memorandum from the USEPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from

consideration, and the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps, described below (from the USEPA's Draft New Source Review Workshop Manual, 1990).[1]

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation.

Step 2. Eliminate all technically infeasible control technologies.

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy.

Step 4. Evaluate most effective controls and document results.

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

Formal use of these steps is not always necessary. However, the USEPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which USEPA believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies, i.e., those that provide the "maximum degree of emissions reduction."

Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each source. These options were identified by researching the USEPA database known as the RACT/BACT/ LAER/Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in USEPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control

[1] "New Source Review Workshop Manual," DRAFT October 1990, USEPA Office of Air Quality Planning and Standards

technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. An available technology is one that is commercially available, meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench-scale or laboratory testing;
- Pilot-scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams' physical and chemical characteristics.

For this BACT analysis, the available control options were identified by querying the USEPA RBLC and by consulting available literature on control options for integrated gasification combined cycle (IGCC) and for nitrogen-based product sources. The analysis also involves review of currently permitted and operating IGCC and nitrogen-based products facilities.

3.0 PROJECT SOURCES SUBJECT TO BACT ANALYSIS

HECA will consist of several facility blocks/systems representing sources of regulated air pollutants that are addressed in this BACT analysis. These main "systems" are essentially the IGCC process, hydrogen production and power generation, and the Manufacturing Complex. To evaluate possible emission control technologies for the IGCC process, it is first important to understand the unique IGCC process and the supporting ancillary plant processes; additional descriptions of other permitted IGCC are provided in Section 5.0 for comparison. Section 6.0 describes the proposed BACT for each source. More detailed process descriptions for the various processes that make up the HECA Project are included in Chapter 2.0 the CEC AFC Amendment. The proposed BACT controls and associated emission rates for each emission unit are summarized in Table 3-1.

HECA includes a source unique to power generation facilities operating at this time – a CTG equipped to combust synthesis gas (syngas). It is important to emphasize that BACT for this source is based on the "best of class" in current diffusion combustor-based syngas fired gas turbine technology. The emissions profile contained in this application for this source is as good as or better than other syngas IGCC permitted to date, as discussed later in this section. However, the IGCC BACT level emissions should not be compared to the NGCC gas turbine technology using dry low-NO_X burner technology emission levels.

Table 3-1
Proposed BACT for Project

Pollutant	Technology	Emission Limit
CTG/HRSG Combustion Turbine (excluding Startup/Shutdown conditions)		
NO_X	Diluent Injection, Selective Catalytic Reduction (SCR), Limited operation on natural gas	2.5 ppm NO_X at 15% O_2 on hydrogen-rich fuel, 3-hour average
		4 ppm NO_X at 15% O_2 on natural gas fuel, 3-hour average
CO	Good Combustion Practice (GCP), CO Catalyst, Limited operation on natural gas	3 ppm CO at 15% O_2 on hydrogen-rich fuel, 3-hour average
		5 ppm CO at 15% O_2 on natural gas fuel, 3-hour average
PM/PM_{10}	GCP, Gas Cleanup, Gaseous Fuels, pipeline quality natural gas	15 lb/hr on hydrogen-rich fuel and natural gas fuel
SO_2	Hydrogen-rich Gas cleanup, pipeline quality natural gas	≤ 2 ppmv total sulfur in hydrogen-rich syngas, ≤ 10 ppmv total sulfur in PSA off-gas
		≤ 0.75 grain/100 SCF (12.65 ppm for natural gas)
VOC	CO Catalyst, Limited operation on natural gas	1 ppm VOC at 15% O_2 on hydrogen-rich fuel, 3-hour average
		2 ppm VOC at 15% O_2 on natural gas fuel, 3-hour average
NH_3	SCR	5 ppm NH_3 slip on hydrogen-rich fuel and natural gas fuel
Coal Dryer		
PM/PM_{10}	Baghouse	0.001 grain/scf outlet dust loading
Cooling Towers		
PM/PM_{10}	High Efficiency Drift Eliminators, Total Dissolved Solids (TDS) limit in circulating water, and Good Operating Practice	0.0005 % drift as percent of the circulating water
Auxiliary Boiler, Natural Gas 213 MMBTU/hr		
NO_X	Low-NO_X burner and SCR	5 ppm NO_X at 3% O_2
CO	GCP, annual tune-up	50 ppmvd at 3% O_2
PM/PM_{10}	GCP, PUC grade natural gas fuel	0.005 lb/MMBtu heat input
SO_2		0.00285 lb/MMBtu (12.65 ppm for natural gas)
VOC		0.004 lb/MMBtu heat input
NH_3	SCR	5 ppm NH_3 slip natural gas fuel
Emergency Diesel Engines (2 Emergency Generators; 2,922 hp each)		
NO_X	Certified EPA Tier 4 diesel engine, combustion controls, restricted operating hours, Low Sulfur Diesel fuel	0.5 g/bhp/hr
CO		2.6 g/bhp/hr
PM/PM_{10}		0.07 g/bhp/hr
SO_2		Very Low Sulfur Diesel fuel (15 ppmw or less)
VOC		0.3 g/bhp/hr

Table 3-2
Proposed BACT for Project (Continued)

Pollutant	Technology	Emission Limit
Emergency Diesel Engine (Fire Pump; 565 hp)		
NO_X	Certified EPA Tier 4 diesel engine, combustion controls, restricted operating hours, Low Sulfur Diesel fuel	1.5 g/bhp/hr
CO		2.60 g/bhp/hr
PM/PM_{10}		0.015 g/bhp/hr
SO_2		Very Low Sulfur Diesel fuel (15 ppmw or less)
VOC		0.14 g/bhp/hr
Gasification Flare		
NO_X, CO, PM/PM_{10}, SO_2	GCP, gaseous fuel only, Gas cleanup/Limit on reduced sulfur in hydrogen-rich fuel	
VOC	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, VOC destruction of ≥ 98.5%	
Rectisol® Flare		
NO_X, CO, PM/PM_{10}, SO_2	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, gas cleanup/limit on reduced sulfur in syngas	
VOC	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, VOC destruction of ≥ 98.5%	
SRU Flare (Sulfur Recovery System)		
NO_X, CO, PM/PM_{10}	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases	
SO_2	Caustic Scrubber	
VOC	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, VOC destruction of ≥ 98.5%	
Thermal Oxidizer (Sulfur Recovery System) (excluding Startup/Shutdown conditions)		
NO_X	GCP	0.24 lb/MMBtu
CO		0.20 lb/MMBtu
PM/PM_{10}		0.0076 lb/MMBtu
SO_2	GCP, Gas cleanup to ≤ 10 ppmv H_2S	2 lb/hr process vent gas
VOC	GCP	0.0055 lb/MMBtu
CO_2 Vent		
CO	Gas Cleanup, restricted operating hours	1,000 ppmv
VOC		40 ppmv
H_2S	Acid Gas Removal	10 ppmv
Feedstock		
PM/PM_{10}	Dust Collector, adequate moisture to prevent visible emissions in excess of 5% opacity	0.005 grain/scf outlet dust loading
Ammonia Plant Heater, Natural Gas 55 MMBtu/hr		
NO_X	Low-NO_X burner, limited operation	9 ppm NO_X at 3% O_2
CO	GCP, annual tune-up	50 ppmvd at 3% O_2
PM/PM_{10}	GCP, PUC grade natural gas fuel	0.005 lb/MMBtu heat input
SO_2		0.00285 lb/MMBtu (12.65 ppm for natural gas)
VOC		0.004 lb/MMBtu heat input

Table 3-2
Proposed BACT for Project (Continued)

Pollutant	Technology	Emission Limit
Urea HP Absorber		
NH_3	Wet scrubber	11.1 lb/hr
Urea LP Absorber		
NH_3	Wet scrubber	2.0 lb/hr
Urea Pastillation		
PM/PM_{10}	Baghouse	0.001 grain/dscf
Nitric Acid Plant		
NO_X	SCR	0.2 lb/ton (15 ppmv in vent gas)
NH_3	SCR	5 ppm NH_3 slip
Ammonium Nitrate Plant		
PM/PM_{10}	Wet scrubber	0.2 lb/hr
Fugitives		
VOC	LDAR, leak detection for valves and connectors with VOC > 100 ppmv above background, and for pumps and compressor seals with VOC > 500 ppmv above background	Varies

Source: HECA Project.

Notes:
BACT = best available control technology
CO = carbon monoxide
CPUC = California Public Utility Commission
CTG = combustion turbine generator
FGR = flue gas recirculation
GCP = good combustion practice
LDAR = leak detection and repair
MMBtu = million British thermal units
NH_3 = ammonia
NO_X = nitrogen dioxide
O_2 = oxygen
PM/PM_{10} = particulate matter/particulate matter less than 10 microns
ppm = parts per million
ppmv = parts per million by volume
ppmvd = parts per million volumetric dry
ppmw = parts per million by weight
SCF = standard cubic feet
SCR = selective catalytic reduction
SO_2 = sulfur dioxide
VOC = volatile organic compound

4.0 CONSIDERATION OF ALTERNATIVE GENERATING TECHNOLOGY

This section addresses recent guidance relating to the need for consideration of alternative electrical generating technologies for the proposed Project, as part of the BACT analysis. Compared to pulverized coal (PC)-fired boilers and circulating fluidized bed (CFB) boilers, the proposed IGCC process is the very lowest emitting solid fuel-based electricity generating technology available, and selection of a completely different solid fuel-based generating technology would not result in lower emissions. Later portions of this BACT analysis address the specific controls that are proposed to minimize the emissions from the proposed IGCC process. In addition, Section 5.0 provides descriptions of other permitted IGCC facilities for more in-depth comparison.

The first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions of the source and pollutant under evaluation. The most common control technologies considered in a BACT analysis are add-on control measures and inherent process characteristics that minimize generation of pollutants, in addition to process or work practice modifications to improve the emissions performance of a proposed Project. These types of process modifications/measures, when applicable, are properly considered in a BACT analysis.

In contrast, consideration of alternatives that would involve completely "redefining the design" of the proposed process are not required to be considered (1990 Draft New Source Review Workshop Manual, Section IV.A.3). Alternative generating processes, such as natural-gas–fired combined-cycle plants, represent a completely different family of power generation plant designs from IGCC. Although there are certain types of components in common, such as cooling towers and steam-driven turbine generators, the technical basis for a gas-fired plant differs markedly from that of an IGCC facility.

Because CFB or PC boilers or a natural-gas–fired electrical generating plant would be a completely different process, and represent "redefining the design" compared to IGCC, it is reasonable to conclude that the USEPA would not require that the BACT analysis for HECA compare these different technologies. This point was reinforced in a December 13, 2005 letter from Stephen Page, Director of the USEPA's OAQPS, to E3 Consulting, LLC regarding BACT requirements for proposed coal-fired power plant projects. In that letter, the USEPA clarified that a BACT analysis need not consider an alternative "which would wholly replace the proposed facility with a different type of facility." Some specific cases regarding alternative design and project definitions are discussed below in Section 4.1. The decisions in these cases provide additional clarity for excluding alternative technologies that redefine the source from BACT procedures for this Project. Section 4.2 gives more details regarding the HECA source and purpose, providing further justification for excluding alternative technologies from this BACT analysis.

4.1 Case Studies for Alternative Technology Methodology and Applicability to HECA Project

Desert Rock Energy Company LLC proposed to build a 1,500 MW coal-fired electric generating facility in New Mexico. USEPA Region 9 issued a final PSD permit on July 31, 2008, which was appealed by four different parties. On September 24, 2009, the U.S. Environmental Appeals Board issued a remand, both granting the Region's request for a voluntary remand, as well as remanding for BACT review to consider IGCC technology as an alternative process/control technology. (*In re: Desert Rock Energy Company, LLC, PSD Appeal Nos. 08-03 et al. (September 24, 2009) ["Desert Rock."])*

The Desert Rock decision stated that "the Region abused its discretion in declining to consider IGCC as a potential control technology in step 1 of its BACT analysis for the facility. Although the Region has broad discretion in determining whether imposition of a control technology would "redefine the source," the Board concludes that, based on the administrative record for this case, the Region's analysis is inadequate for two reasons. First, the Region did not provide a rational explanation of why IGCC would redefine the source, especially when the applicant itself had indicated in its initial application that IGCC was a technology that could be considered for the facility (i.e., could satisfy its business purpose), thereby suggesting that IGCC would not redefine the source. Second, the Region failed to adequately explain its conclusion in light of previously issued federal permits at similar facilities in which IGCC *had* been considered as a BACT step 1 production process and had not been considered a "redefinition of the source."

The Desert Rock project's failure to consider IGCC as an alternate technology is not directly relevant to the HECA Project's BACT analysis, because HECA is already proposing an IGCC, and has in fact, proposed to go even further than a traditional IGCC. Traditional IGCCs burn syngas containing large quantities of both hydrogen and CO. In contrast, HECA is achieving similar or lower criteria emissions while significantly reducing greenhouse gas (GHG) emissions by the removal and sequestration of the carbon pre-combustion, and burning a hydrogen-rich syngas instead. [Note: GHG BACT is addressed in a separate GHG BACT document, and is only mentioned here as part of the alternative technology discussion.]

Nevertheless, the Desert Rock decision is instructive in that it provides a framework for determining if a particular technology "redefines the source". Specifically, the Board articulated the proper test to be used to answer that question. As the Board explained, the permit applicant initially "defines the proposed facility's end, object, aim, or purpose— that is the facility's basic design…." The inquiry, however, does not end there. The permit issuer should take a "hard look" at the applicant's determination in order to discern which design elements are inherent for the applicant's purpose and which design elements "may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility," while keeping in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility."

In a sense, HECA is adhering to the Desert Rock decision by proposing an IGCC-based plant with coal and petcoke as feedstock, rather than a conventional coal boiler. In addition, the

Project goes even further than traditional IGCC, which burn the syngas containing both hydrogen and CO. HECA will remove the majority of the carbon (present in the syngas as CO or CO_2) and will fuel the combustion turbine with a hydrogen-rich syngas which drastically reduces CO_2 emissions.

USEPA issued similar guidance regarding what needs to be included in a BACT analysis in their December 15, 2009 response to objections raised by petitioners to the Cash Creek Generation LLC project in Kentucky, and objected to the permit issued by the Kentucky Department of Air Quality (KY DAQ) for a 770 MW IGCC plant proposed for Cash Creek, Kentucky (*In the Matter of Cash Creek Generation, LLC, Henderson, Kentucky*, Petition Nos. IV-2008-1 and IV-2008-2 ["*Cash Creek*"]). One of the reasons for objection was that KY DAQ did not adequately justify their lack of consideration of the use of natural gas as an alternative in the BACT analysis. USEPA pointed out that a BACT analysis should normally consider the use of "clean fuels" unless such an option is not "available" or would fundamentally redefine the design of the source. The USEPA maintained that KY DAQ did not provide sufficient justification and a reasoned basis as to why the use of natural gas would "redefine the source." In this decision, USEPA references and repeats the same analytical framework described above in the Desert Rock decision (i.e., evaluate proposed facility purpose and evaluate which design elements are inherent to that purpose).

The USEPA specifically stated that they were not indicating the proposed emission limits did not represent BACT, "only that the present permit record does not provide a sufficient rationale to demonstrate the adequacy of the BACT determinations for this facility."

This aspect of the Cash Creek situation is somewhat analogous to HECA's. In both cases, the applicant is proposing use of solid feedstocks and syngas fuels, and the USEPA has questioned the possible need to consider natural gas as an alternative. However, the USEPA very clearly states that its objection to the Cash Creek permit does not indicate that the use of natural gas is BACT. The USEPA states in the *Cash Creek* decision (emphasis added):

> "EPA's conclusion here… should in no way be interpreted as EPA expressing a policy preference for construction of natural-gas fired facilities over IGCC facilities to generate electricity. EPA supports the development and use of a broad range of technologies across the energy sector including those that will enable the sustainable use of coal. **The deployment of lGCC technology is one of the important technologies and a positive strategy to reduce emissions from coal-fired electricity generation. Technology that enables the United States to use its appreciable reserves of coal in an environmentally sustainable manner is critical to achieving the goals of the PSD program and maintaining compliance with the NAAQS by reducing conventional air pollutants**...This Order should not be interpreted to establish or imply an EPA position that PSD permitting authorities should conclude, under all circumstances, that BACT for a proposed electricity generating unit is firing such a unit with natural gas" (*Cash Creek*, pg. 9).

Another relevant Environmental Appeals Board (EAB) decision worth noting is *Prairie State* (*In re Prairie State Generating Company*, PSD Appeal No. 05-05 [August 24, 2006) "*Prairie State*]). EAB concluded in the *Prairie State* decision that the basic design of the proposed power plant at issue there was to generate electricity using solely coal originating from a coal mine at which the power plant was to be located (i.e., mine-mouth plant). Given this basic design, the EAB stated that requiring the applicant and the state permit agency to consider the use of *another source of coal*—specifically, low-sulfur western coal—in the BACT analysis for the plant would constitute redesigning the source.

This Prairie State decision shows that where there is a legitimate business purpose to using a particular fuel source, use of another cleaner fuel source is not necessarily required to be considered if the alternative fuel would be incompatible with the basic design and purpose of the proposed facility.

To summarize, in these recent USEPA decisions, the following analytical framework is provided to evaluate whether an option may be excluded from a BACT analysis because it redefines the proposed source:

- First, the permitting authority should determine from the particular record how the permit applicant defines the proposed facility's end, object, aim, or purpose (the "basic" or "fundamental" design of the facility).

- The next step is for the permitting authority to take a "hard look" at the applicant's purpose to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.

- As part of the latter step, the permitting authority should keep in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility.

4.2 Purpose and Design of HECA as Applied to BACT Alternative Technology Methodologies

The purpose of the Project is not merely the generation of electricity. As identified in other areas of the application, the three key interrelated elements of the Project design and purpose can be summarized as follows:

- Use of solid carbon feedstocks (petcoke and/or coal) to produce low-emission electricity;
- Generation of hydrogen for low-carbon electricity and nitrogen-based products in an integrated Manufacturing Complex; and
- Capture of CO_2 for reduced GHG emissions and transporting CO_2 for use in enhanced oil recovery (EOR).

The design and purpose of the Project is outlined below and presented in detail in the AFC Amendment (2012).

The Project will gasify a 75 percent coal and 25 percent petroleum coke (petcoke) fuel blend to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, which will be used to generate low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based products in an integrated Manufacturing Complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR).

The products and power produced by the Project have a lower carbon footprint than similar products. This low-carbon footprint is accomplished by capturing more than 90 percent of the CO_2 in the syngas and transporting CO_2 for use in EOR, which results in simultaneous sequestration (storage) of the CO_2 in a secure geologic formation. CO_2 will be transported for use in EOR in the adjacent Elk Hills Oil Field (EHOF), which is owned and operated by Occidental of Elk Hills, Inc. (OEHI). As discussed below, the OEHI EOR project will be separately permitted by OEHI through the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR). The EOR process results in sequestration (storage) of the CO_2.

Project GHG emissions (e.g., CO_2) will be reduced through carbon capture and CO_2 EOR resulting in simultaneous sequestration.

The Project is owned by SCS Energy California LLC, with the prime objective of producing hydrogen for low-carbon polygeneration.

In addition, the Project has been selected as part of the Clean Coal Power Initiative (CCPI), a cost-shared collaboration between the federal government and private industry to increase investment in low-emission coal technology by demonstrating advanced coal-based power generation technologies prior to commercial deployment.

DOE's purpose, aim, and goal in supporting the Project, as stated on the above referenced website, is: "to accelerate the development of advanced coal technologies with carbon capture and storage at commercial-scale. These projects will help to enable commercial deployment to ensure the United States has clean, reliable, and affordable electricity and power."

DOE's relevant stated goals for this cost sharing program are to:

- make progress toward a target CO_2 capture efficiency of 90 percent;
- make progress toward a capture and sequestration goal of less than 10 percent increase in the cost of electricity for gasification systems; and
- capture and sequester or put to beneficial use an amount of CO_2 emissions in excess of the minimum of 300,000 tons per year required by Clean Coal Power Initiative.

This evaluation predominantly presents how a change to natural gas fuel would be considered "redefining the design of the source" in the context of the source's "design" being its "purpose". The next few paragraphs discuss the actual physical/engineering design of the source (i.e., equipment types, processes, etc.) that would require "redesigning" to accommodate a change to natural gas as the primary fuel or feedstock.

A production process is typically defined in terms of its physical and chemical unit operations used to produce the desired product from a specified set of raw materials. The specified raw materials of the IGCC process are solid carbon feedstocks such as petcoke and coal. Many of the unit operations and processes that have been designed for HECA are specific to the use of coal/ petcoke feedstocks, and to the removal of sulfur and CO_2 from the syngas, and the production of nitrogen-based products from the hydrogen-rich syngas. Use of natural gas as a feed stock would require substantial re-design of the facility due to these processes. These include:

- Solid fuel handling systems and baghouses
- Gasifier
- Sour shift/gas cooling
- Mercury removal
- Acid gas removal
- Sulfur Recovery Unit and Tail Gas Treating Unit
- SRU, Gasification and Rectisol® Flares
- Air Separation Unit
- CO_2 Absorption and Compression
- CO_2 Pipeline (3.4 miles)
- Nitrogen-based product from syngas.

In addition, the combustion turbine used in this Project has been specifically designed by Mitsubishi to fire hydrogen-rich fuel. While it is capable of firing natural gas, different turbines/ burners would be used if natural gas were the primary fuel.

Based on the criteria previously discussed, and the general stated purposes of the Project, the following paragraphs analyze the various Project elements with an emphasis on their necessity and inherent inclusion in the basic Project design/purpose.

As detailed previously, there are three key interrelated elements of the Project design and purpose. Each of these elements is critical to the objectives of the Project and the design of the source. These are legitimate business goals, and are important to the Project sponsors. They are not incidental, but rather essential Project preferences. These goals preclude the use of natural gas, or the construction of a natural-gas combined cycle power plant as an alternative. Further discussion of these points is provided in the following paragraphs.

Coal and petcoke, a by-product of petroleum refining, are the raw materials integral to the process. They are historically cheaper (per British thermal unit) and more widely available in the United States than natural gas. The purpose of the Project is to use these traditional solid raw materials/fuels, which are readily-available, and demonstrate the generation of clean, low-carbon electricity and nitrogen based products. Although the electricity generation is an important revenue stream that helps support the economic justification for the Project, the goals of the Project will clearly not be achieved if the electricity is generated by the use of natural gas or other non-solid fuel. Likewise the use of natural gas would not qualify for funding or meet the objectives of DOE's Clean Coal Power Initiative.

Second, the Project intends to generate hydrogen for the production of electricity and nitrogen-based products. Hydrogen is one of the cleanest, purest fuels that can be combusted to generate electricity, especially in regards to GHG emissions. However, hydrogen use for this purpose has not yet been demonstrated in a large-scale application. This Project is revolutionary in the advancement of clean fuel production and electricity generation, as well as reduction of GHGs through low-carbon fuels. The Project will take the revolutionary step of producing clean gaseous hydrogen-rich fuel from some of the most abundant solid fuel resources in the U.S.: petcoke and coal. This hydrogen-rich fuel will be used for both the generation of electricity and production of nitrogen-based products. The production of hydrogen is a key element of the Project.

Third, the Project will demonstrate the capture of over 90 percent of the carbon from the fuel, prior to combustion in the turbines or use in the Manufacturing Complex. The simple combustion of natural gas for electricity generation would not achieve this goal. Likewise, the "gasification" of natural gas would be superfluous. The power generation portion of the Project, which uses syngas with the majority of the carbon removed prior to combustion, results in CO_2 emissions of approximately 400 pounds per megawatt hour (lb/MWh). This is less than half of the CO_2 emissions from a typical natural gas-fired simple cycle combustion turbine of 1,100 lb/MWh and easily complies with U.S. and California's stringent GHG emissions performance standard (EPS) for electricity generation of 1,000 and 1,100 lb/MWh, respectively. The CO_2 that is captured from the syngas will be used for sequestration and EOR in the Elk Hills Oil Field in San Joaquin Valley, California. This sequestration step is significant as a demonstration for the DOE funding, as well as integral to the financial objectives of the Project. The use of EOR to recover local petroleum reserves increases the United States' energy independence.

For all the above reasons, it is clear that the use of natural gas as the primary fuel to the combustion turbine, as the feedstock to the gasification process or raw material for production of nitrogen-based products would not achieve the inherent business purposes of the Project. Hydrogen generated from solid fuels with advanced pollution controls has great promise as a clean source of electricity and nitrogen based products. However, it has not yet been used or demonstrated in large scale application. The Project is an important first step in the advancement of clean fuel production and electricity generation, as well as reduction of GHGs through the use of low-carbon fuels. It is vital to the Project's goals, and to the DOE Clean Coal Project demonstration, that solid petcoke/coal feeds be used to demonstrate that these abundant resources can be used in an environmentally-sensitive manner to generate low-carbon electricity and capture and sequester carbon dioxide to reduce impacts of GHGs, along with the production of nitrogen-based products from a low carbon fuel. The use of natural gas would simply not fulfill these business, project and national energy program purposes and would constitute a substantial redesign of the source.

5.0 OTHER PERMITTED IGCC PROJECTS

The available control options were identified by querying the RBLC database and by consulting available literature on control options for IGCC. Applications and/or permits from a number of

other IGCC facilities that have completed the New Source Review process were also reviewed to provide additional reference material for this BACT analysis.

There are currently two existing operational, commercial-sized IGCC facilities in the United States. These were examined for this BACT determination.

- Duke Energy, Wabash River Generating Station, West Terre Haute, Indiana.
- Tampa Electric Company, Polk Power Station, Mulberry, Florida.

Wabash River Generating Station: The Wabash River Coal Gasification Repowering Project includes a gasification island with a General Electric (GE) E-Gas two-stage, oxygen blown gasifier and GE MS 7001FA turbine with HRSG generating 262 MW (net). This facility has been operating since 1995. NO_X emissions are permitted at 25 parts per million by volume, dry basis (ppmvd) at 15 percent oxygen (0.15 pound per million British thermal units [lb/MMBtu]). Steam injection is used to control NO_X. CO emissions are permitted at 15 ppmvd.

Tampa Electric Company – Polk Power Station: The facility includes a GE oxygen-blown gasifier with full heat recovery using both radiant and convective syngas coolers. The GE STAG-107FA power block integrates process syngas, steam, and nitrogen. This IGCC facility has been operating since 1996. NO_X emissions are permitted at 15 ppmvd at 15 percent oxygen (0.055 lb/MMBtu). Nitrogen injection is used to control NO_X. CO emissions are permitted at 14 ppmvd.

The proposed NO_X and CO emissions from the CTG/HRSG at HECA will be significantly lower than currently operating IGCC turbines.

A brief summary of the other recently permitted IGCC plants in the United States and their emissions limits is presented below:

- Duke Energy, Edwardsport Generating Station
- Christian County Generation (formerly ERORA Group), Taylorville Energy Center
- ERORA Group, Cash Creek Generation Station (CCGS)
- Hyperion Energy Center
- Mississippi Power Company, Kemper IGCC Facility
- Summit Power TCEP, IGCC Power Plant

The air permits, BACT analyses, and additional literature were reviewed for each of these recently permitted IGCC facilities. Each facility is discussed briefly below. The emissions associated with the CTG/HRSG at each facility are listed in Table 6-1 in ppmvd and/or lb/MMBtu, depending upon available data.

Duke Energy, Edwardsport Generating Station: Duke Energy Indiana, owner of Edwardsport Generating Station, obtained approval, via Indiana Department of Environmental Management Significant Modification Title V Permit, to install an IGCC facility in Knox County, Indiana. The Title V Significant Modification Permit was issued in January 2008 and is expected to start commercial operation in 2012. The 630 MW (net) IGCC plant will replace four

older, less efficient generating units capable of generating approximately 160 MW at the Edwardsport site. The Edwardsport Generating Station is expected to use coal as feedstock, and SCR as add-on control to minimize NO_X emissions from the plant. The SCR system is being installed on a trial basis to investigate technical feasibility for effective operation in recognition of technical uncertainties posed by SO_2 residuals, ammonia slip, and potential inorganic precipitants. The SCR system is not required to demonstrate compliance with federal or state statutes.

The Edwardsport NO_X, CO and PM_{10} emission rates for both syngas and natural gas are higher than HECA; SO_2 and VOC emissions for syngas are higher and for natural gas are lower.

Christian County Generation – Taylorville Energy Center: Christian County Generation LLC is developing the Taylorville Energy Center, a 716 MW (gross) IGCC facility to be located in Christian County, southern Illinois. Taylorville Energy Center obtained a draft Illinois Environmental Protection Agency air permit in October 2011. Final public comments were due December 31, 2011; a final permit has not yet been issued. Commercial operation is expected to start in 2014. Taylorville Energy Center proposed to use Siemens gasification technology and local coals (Illinois coal) as the feedstock. The Taylorville Energy Center will use a Rectisol® acid gas removal (AGR) system, for syngas cleanup followed by a Methanation Unit in the gasification process to produce Substitute Natural Gas (SNG), which has virtually the same composition as natural gas. Because the SNG is essentially the same as natural gas, the combustion turbine is designed to operate on natural gas. BACT for NO_X will be dry low-NO_X (DLN) burners and SCR.

The technology chosen for the Taylorville Energy Center is significantly different from that proposed for HECA. HECA will burn primarily hydrogen-rich fuel with diffusion burners in the CTG. Taylorville Energy Center has chosen DLN burners to combust natural gas and synthetic natural gas (which has the same composition as natural gas). These are not comparable technologies.

ERORA Group – Cash Creek Generation Station: The ERORA Group is developing the CCGS IGCC facility, to be located near Owensboro, Henderson County, Kentucky. CCGS obtained a final Kentucky DAQ air permit in January 2008 and is expected to start commercial operation in 2012. The 770 MW (gross) IGCC proposes to use GE Energy gasification technology and local coals (Kentucky coal) as the feedstock. The CCGS will use a Selexol® AGR system to clean up the syngas. CCGS will use SCR to minimize NO_X emissions from the plant; this will allow them to minimize the cost to acquire NO_X allowances from the market, although SCR is not required for BACT purposes. ERORA notes that in order to increase the chance that the SCR system will work in this unproven application on coal-derived syngas, higher sulfur removal will be required, and can be achieved by using Selexol® instead of methyldiethanol-amine (MDEA).

The CCGS emission rates for all pollutants for both syngas and natural gas are higher than HECA.

Hyperion Energy Center: The South Dakota Department of Environmental and Natural Resources issued a PSD permit for the Hyperion Energy Center on August 20, 2009, and a revised PSD permit in September 2011. The facility will consist of a greenfield petroleum refinery and an IGCC plant, to be located in Union County, South Dakota. The IGCC plant will use petroleum coke as primary feedstock, and is designed to provide the refinery with up to 450 million cubic feet per day of hydrogen, 200 MW (net) of electricity, and 2.4 million pounds of steam per hour. The application did not specify the type of combustion turbine to be used. The project can generate up to 532 MW gross from combustion of syngas.

The co-located refinery will not be able to make enough petroleum coke to supply the IGCC, so additional fuel will be imported to make up the energy shortfall. Hyperion was permitted for two mutually exclusive configurations for the power plant. The first configuration, Option 1, is termed the "maximum coke design case," and will use imported solid fuels (coke and/or coal) to meet the energy needs. In this configuration, the combustion turbines will be fired with hydrogen-rich syngas in the diffusion burners, and the HRSGs will be fired with both syngas and tailgas from the plant's pressure swing absorption (PSA) process (which is part of its process for generating hydrogen for use by the refinery processes) and ultra-low sulfur distillate as a backup fuel. For NO_X control, the use of low-NO_X duct burners, diluent injection, and SCR was determined to be BACT for Option 1 when combusting syngas.

The second configuration, Option 2, is termed the "natural gas design case." In this configuration, the turbines will be fired with natural gas as the primary fuel, and ultra-low sulfur distillate as a backup fuel. The HRSGs will be fired with natural gas and PSA tailgas. For NO_X control, the use of low-NO_X duct burners, DLN combustion burners, and SCR was determined to be BACT for Option 2 combusting natural gas. This configuration (using no syngas fuel in the turbine) is fundamentally different from HECA's proposed turbine operation, because Hyperion will use DLN burners in the turbine. Therefore, we have not used this configuration in our comparison, but instead focused our comparison on the Hyperion "maximum coke design case," which is more similar to the HECA Project.

These two options are mutually exclusive turbine configurations: one or the other will be selected, not a combination of the two. Thus, only Option 1 will be compared to the technologies chosen for the HECA Project.

For Option 1, the use of low-NO_X duct burners, diluent injection, and SCR was determined to be BACT with NO_X emissions of 3 ppmvd when firing syngas and PSA tailgas, and 6 ppmvd for backup on distillate oil. The Hyperion NO_X emission rate for syngas combustion is higher than HECA.

For SO_2 and particulate, the permitted Hyperion IGCC BACT control technology is syngas sulfur cleanup by physical absorption (Rectisol®). For CO and VOCs, the use of oxidation catalyst and good combustion practice was selected as BACT. These are the same control technologies proposed as BACT by HECA with similar emission rates. It should be noted that

some of the pollutant limits for this facility are based on long-term (24-hour and 365-day) rolling averages.

Mississippi Power Company, Kemper IGCC Facility: The Mississippi Department of Environmental Quality issued a final PSD permit for the Kemper IGCC Facility on March 9, 2010. Commercial operation is expected to start in 2014. The facility will be located in Kemper County, Mississippi. The primary fuel for the proposed facility will be syngas derived from lignite coal. Natural gas will be used as a secondary fuel. The facility will use Siemens 5000F turbines, and generate a 582 MW of electric power.

For NO_X, BACT was determined to be the use of good combustion and operating practices for a diffusion flame combustion turbine when using syngas. BACT when using natural gas was determined to be the use of steam or water injection in conjunction with the use of SCR. (Note: SCR was not required when firing syngas because of the project's use of lignite coal and an oxygen-blown gasifier. When using syngas fuel, the permit does not require ammonia to be added to the SCR, allowing the exhaust gas to pass through the system without forming ammonium sulfates.) The Kemper NO_X emission rate for syngas combustion is higher than HECA; and for natural gas, combustion is the same as HECA.

For CO and VOC, the use of good combustion practice was selected as BACT. (Note: oxidation catalyst was not required.) For SO_2, use of the Selexol® AGR system was determined to be BACT. For particulate, BACT was determined to be the use of clean fuels and good combustion practices. The Kemper permit does not require as stringent emissions controls as those proposed by HECA.

Summit Texas Clean Energy, LLC (Summit) TCEP, IGCC Power Plant: The Texas Commission on Environmental Quality issued a final PSD permit for Summit's Texas Clean Energy Project (TCEP) IGCC Facility on December 28, 2010. Commercial operation is expected to start in 2015. The facility will be located in Odessa, Ector County, Texas. The primary fuel for the proposed facility will be syngas derived from coal. Natural gas will be used as a secondary fuel. The facility will use Siemens gasifiers fueling a single Siemens 5000F turbine and one steam turbine, and will generate 400 MW (gross) of electric power.

For NO_X, combustion control diluent injection and SCR was determined to be BACT. When firing on syngas, diluent injection will provide combustion control; when firing on natural gas, steam injection will provide combustion control. The TCEP NO_X emission limit was set to 15 ppmvd, based on a 1-hour averaging time for both syngas and natural gas. There is also a long-term NO_X limit of 3.5 ppmvd for syngas combustion, and 2.5 ppmvd for natural gas combustion, which is based on a 30-day rolling average. The short-term TCEP NO_X limits for both syngas and natural gas are significantly higher than HECA. The long-term TCEP NO_X limit on syngas is higher than HECA. Although the long-term TCEP limit for natural gas is lower than HECA, HECA will not operate the turbine on natural gas for more than 2 weeks in a given year, so this long-term rate is not comparable.

For CO and VOC, the use of good combustion practice was selected as BACT. For SO_2, use of the clean, low sulfur fuel was determined to be BACT. For particulate, BACT was determined to be the use of clean fuels and good combustion practices. It should be noted that some of the

emission limits for this facility (for both syngas and natural gas) are based on 30-day rolling averages. The TCEP emission rates for all other pollutants for both syngas and natural gas are higher than HECA, except that VOC is lower than HECA for natural gas.

6.0 SOURCE-SPECIFIC BACT ANALYSIS

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants that would be emitted from the HECA Project to determine appropriate BACT emission limits. This BACT analysis is based on the current state of IGCC and nitrogen-based product production technology, energy and environmental factors, current expected economics, energy, and technical feasibility.

6.1 CTG/HRSG BACT Analysis

The following is the BACT analysis for the proposed combustion turbine. The proposed combustion turbine will be a Mitsubishi Heavy Industries (MHI) 501 GAC® model turbine with a gross capacity of approximately 405 MW. The MHI 501 GAC® is a new turbine model designed to optimally use hydrogen-rich fuel and natural gas as a backup fuel, and includes changes to the fuel system, combustion system, and hot gas path. The use of hydrogen-rich fuel requires the use of a diffusion-type combustor, because the high concentration of hydrogen precludes the use of DLN combustor technology. HECA selected Rectisol® as the syngas cleanup control technology to remove sulfur dioxide and other impurities from the hydrogen-rich fuel stream before entering the CTG/HRSG.

The air permits, BACT analyses, and additional literature for each of the recently permitted IGCC facilities discussed in the last section were reviewed. Table 6-1 summarizes the criteria pollutant emission levels permitted for the combustion turbine units at each facility. This table also shows the proposed BACT limits for the HECA Project as a comparison.

6.1.1 Nitrogen Oxides BACT Analysis for the CTG/HRSG

The criteria pollutant NO_X is primarily formed in combustion processes via the reaction of elemental nitrogen and oxygen in the combustion air (thermal NO_X), and the oxidation of nitrogen contained in the fuel (fuel NO_X). The hydrogen-rich fuel produced in the Project contains negligible amounts of fuel-bound nitrogen; therefore, it is expected that essentially all NO_X emissions from the CTG/HRSG will originate as thermal NO_X. The rate of formation of thermal NO_X in a combustion turbine is a function of residence time, oxygen radicals, and peak flame temperature.

Front-end NO_X control techniques are aimed at controlling one or more of these variables during combustion. Examples include dry low-NO_X combustors, flue gas recirculation, and diluent injection (steam, water, or nitrogen). Higher peak flame temperature during combustion may increase thermodynamic efficiency, but it also increases the formation of thermal NO_X. The injection of an inert diluent such as atomized water, steam, or nitrogen into the fuel gas line or the high-temperature region of a combustor flame serves to inhibit thermal NO_X formation by reducing the peak flame temperature.

For the Project's turbine, nitrogen is used as a diluent that reduces thermal NO_X produced when hydrogen-rich fuel is combusted. Water is used as a diluent when natural gas is combusted. This method effectively lowers the fuel heat content, and consequently the combustion temperature, thereby reducing NO_X emissions.

SCR is a technology that achieves post-combustion reduction of NO_X from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of nitrogen oxides and ammonia to nitrogen and water. SCR will be used when firing hydrogen-rich fuel or natural gas.

The Project selected SCR and diluent injection technology to control NO_X emissions from the CTG/HRSG. This combination of control processes will achieve an NO_X emission rate of 2.5 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing hydrogen-rich fuel; or 4 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing natural gas.

It is necessary to recognize the fundamental differences between natural-gas-fired and hydrogen-rich fuel-fired combustion turbines in evaluating these techniques. Compared to natural gas and substitute natural gas (SNG), hydrogen-rich fuel has a much higher hydrogen content (natural gas is often over 90 percent methane), and a much lower heating value (about 250 Btu/scf for hydrogen-rich fuel versus 1,000 Btu/scf for natural gas). HECA will be fired primarily on hydrogen-rich fuel. The other power plants used for comparison in this analysis are fired on syngas. Plants firing SNG will be discussed, but are not comparable to HECA, because SNG is essentially the same as natural gas.

The HECA combined-cycle power-generation unit will primarily combust hydrogen-rich syngas in the combustion turbine, and PSA off-gas plus additional syngas in the duct burners. Certain combustion characteristics of hydrogen-rich syngas, such as flame speed and flame temperature, are substantially different from the more familiar natural gas fuel. Modern combined-cycle units using natural gas typically are equipped with DLN combustors in the combustion turbine. These low-emission burners will typically produce emission levels in the range of 9 to 15 ppmvd NO_X (depending on duct-firing rates) downstream of the duct burners. Thus, a BACT emission limit of 2 ppmvd can be easily achieved with SCR efficiencies of 85 percent or less. The proposed HECA SCR reduction efficiencies significantly exceed the corresponding reduction efficiencies currently needed for a natural-gas–fueled combined-cycle plant to meet the proposed BACT levels.

In the case of hydrogen-rich fuel, natural gas DLN combustors cannot be used, due to the difference in combustion characteristics. Similar-type burners for hydrogen-rich fuel have not been developed. Only diffusion-type combustors are available for this fuel.

HECA requests operation of the combined-cycle unit on natural gas fuel for a limited period of up to 2 weeks per year when the gasifier is unavailable, and during start-up and shut-down. The higher emission rate from combustion of natural gas is caused by the difference in combustion characteristics of natural gas compared to the hydrogen-rich fuel in the diffusion burners.

Table 6-1
Permitted Criteria Pollutant BACT Limits for Combined-Cycle Combustion Turbines at IGCC Facilities

Facility	HECA	Cash Creek Generation Station	Edwardsport Generating Station	Taylorville Energy Center	Hyperion Energy Center	Kemper County IGCC Project	Summit TCEP
Location	Kern County, CA	Henderson County, KY	Knox County, IN	Christian County, IL	Union County, SD	Kemper County, MS	Ector County, TX
Permit Date	Not Yet Permitted	January 2008	June 2007	Public Comment Period on Draft PSD Permit Ended December 31, 2011	September 2011	March 2010	December 2010
Fuel	Hydrogen-based syngas ----- Natural Gas backup	Coal-derived Syngas ----- Natural Gas backup	Coal-derived Syngas ----- Natural Gas backup	Substitute Natural Gas (SNG) and Natural Gas	Petroleum coke-derived Syngas with PSA Tail gas *or* Natural Gas with PSA Tail gas[a] ----- Ultra Low Sulfur Distillate (ULSD) backup	Lignite coal-derived Syngas ----- Natural Gas backup	Coal-derived Syngas ----- Natural Gas backup
MW (gross)	405	770	630 (net)	716	532	582	400
Turbine	MHI 501 GAC®	GE 7FB	GE 7FB	Siemens MHI 501GAC® CT	Not Specified	Siemens 5000F	Siemens 5000F
NO_X	2.5 ppmvd (0.011 lb/MMBtu) hydrogen-rich fuel, 3-hr rolling average; 4.0 ppmvd (0.015 lb/MMBtu) Natural Gas, 3-hr rolling average	5 ppmvd (0.0331 lb/MMBtu) Syngas; 5 ppmvd (0.0246 lb/MMBtu) Natural Gas	5 ppmvd (0.027 lb/MMBtu) Syngas; 0.018 lb/MMBtu Natural Gas	2.0 ppmvd SNG[b] or Natural Gas	3.0 ppmvd (0.018 lb/MMBtu)[c] Syngas/ PSA Tailgas; 2.0 ppmvd (0.012 lb/MMBtu)[d] Natural Gas/PSA Tailgas; 6.0 ppmvd ULSD	0.061 lb/MMBtu Syngas (LHV); 0.015 lb/MMBtu Natural Gas (LHV)	15 ppmvd Syngas or Natural Gas, 1-hr average; 3.5 ppmvd (0.014 lb/MMBtu) Syngas, 30-day rolling average; 2.5 ppmvd (0.009 lb/MMBtu) Natural Gas, 30-day rolling average
SO_2	≤ 2 ppmv in undiluted hydrogen-rich fuel; and ≤ 10 ppmv in PSA off-gas (0.0002 lb/MMBtu); 0.75 grains/100 scf of total sulfur Natural Gas (0.002 lb/MMBtu)	3.8 ppmvd (0.0158 lb/MMBtu) Syngas; 0.0006 lb/MMBtu Natural Gas	0.0138 lb/MMBtu Syngas; 0.0006 lb/MMBtu Natural Gas	0.25 grains/100 scf sulfur in SNG or Natural Gas	1.0 ppmv sulfur in Syngas, 0.5 ppmv in PSA Tail gas (0.0005 lb/MMBtu Syngas/PSA Tail gas); 9 ppmv sulfur in Natural Gas; 15.0 ppmw sulfur in ULSD (0.0015 lb/ MMBtu)	0.004 lb/MMBtu Syngas; 1.9 lb/hr Natural Gas	10 ppmv sulfur in Syngas (0.006 lb/MMBtu); 2 grains/100 dscf in Natural Gas (0.006 lb/MMBtu)
CO	3 ppmvd (0.008 lb/MMBtu) hydrogen-rich fuel; 5 ppmvd (0.011 lb/MMBtu) Natural Gas	0.0485 lb/MMBtu Syngas; 0.0449 lb/MMBtu Natural Gas	0.0441 lb/MMBtu Syngas; 0.0421 lb/MMBtu Natural Gas	4.3 ppmvd SNG or Natural Gas	3.0 ppmv Syngas/PSA Tailgas/ULSD; 3.0 ppmv Natural Gas/PSA Tailgas/ ULSD	0.031 lb/MMBtu Syngas (LHV); 0.063 lb/MMBtu Natural Gas (LHV)	10 ppmvd (0.02 lb/MMBtu) Syngas; 10 ppmvd (0.02 lb/MMBtu) on Natural Gas
PM_{10}	15 lb/hr (0.008 lb/MMBtu) hydrogen-rich fuel or Natural Gas	76 lb/hr[e] Syngas; 57 lb/hr[e] Natural Gas	63 lb/hr[e] Syngas; 29 lb/hr[e] Natural Gas	0.0065 lb/MMBtu SNG or Natural Gas	36.9 lb/hr (0.022 lb/MMBtu) Syngas/ PSA Tailgas; 18.4 lb/hr (0.011 lb/MMBtu) Natural Gas/PSA Tailgas; 36.9 lb/hr (0.022 lb/MMBtu) ULSD	36 lb/hr[c] Syngas; 0.01 lb/MMBtu Natural Gas (LHV)	0.008 lb/MMBtu Syngas or Natural Gas
VOC	1 ppmvd (0.0015 lb/MMBtu) hydrogen-rich fuel; 2 ppmvd (0.003 lb/MMBtu) Natural Gas	NA	0.0016 lb/MMBtu Syngas; 0.0016 lb/MMBtu Natural Gas	0.0013 lb/MMBtu SNG or Natural Gas	0.0017 lb/MMBtu Syngas or Natural Gas	0.005 lb/MMBtu Syngas (LHV); 0.008 lb/MMBtu Natural Gas (LHV)	1 ppmvd (0.0012 lb/MMBtu) Syngas; 1 ppmvd (0.0012 lb/MMBtu) Natural Gas

Notes:

[a] Hyperion turbines are designed to operate in one of two configurations. Option 1 is a turbine designed to burn petcoke-derived syngas with PSA tail gas fired only in the duct burner; diluent injection and SCR are proposed. Option 2 is a natural gas-fired turbine with PSA tail gas fired only in the duct burner; DLN control will be included. These two options are mutually exclusive turbine configuration, one or the other will be selected, not a combination of the two.
[b] DLN technology is feasible for substitute natural gas (SNG) – fired turbines. Emission limits are for SNG firing.
[c] The DLN technology is not applied for this limit, because the technology is not feasible for a hydrogen-rich syngas-fired turbine.
[d] Emission limit for separate natural gas turbine option using DLN and SCR (see footnote a).
[e] PM_{10} lb/hr limits have been prorated to HECA-sized turbine in MW for comparison purposes. This is only done in cases where no other limits (such as lb/MMBtu) are provided.

dscf = dry standard cubic foot
HHV = higher heating value
lb/hr = pounds per hour
lb/MMBtu = pounds per million British thermal units
LHV = lower heating value
MW = megawatt
ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2
ppmv = parts per million by volume
ppmw = parts per million by weight
scf = standard cubic foot

BEST AVAILABLE CONTROL TECHNOLOGY

1. *Identify Control Technologies*

The following NO_X control technologies were evaluated for the proposed CTG/HRSG:

Combustion Process Controls

- Dry Low-NO_X Burner
- Diluent Injection

Post-Combustion Controls

- $SCONO_X$™
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

2. *Evaluate Technical Feasibilities*

- Dry Low-NO_X Combustor

  DLN combustor technology has been successfully demonstrated to reduce thermal NO_X formation from natural-gas combustion turbines. This is done by designing the combustors to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual combustor's flame envelope. Combustor design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed combustor design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_X emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_X formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

  Hydrogen-rich fuel differs from natural gas in heating value, gas composition, and flammability characteristics. Available DLN combustor technologies are designed for natural gas (methane-based) fuels and will not operate on the hydrogen-rich fuel (CO-based) used by an IGCC combustion turbine. DLN combustors are not technically feasible for this application due to the potential for explosion hazard in the combustion section due primarily to the high hydrogen content of the fuel. No manufacturer currently makes DLN combustors that can be used for a combustion turbine fueled by fuels containing significant hydrogen. Thus, DLN combustor is not a technically feasible control option for this unit. [Note that the Hyperion Energy Center has DLN for NO_X BACT for their natural gas design case only. This technology is not combined with the diffusion burner technology (and diluent injection) for the Syngas design case. Therefore, the use of DLN at Hyperion is not comparable to the HECA facility.]

  The MHI combustion turbine proposed for the HECA Project must use a diffusion combustor, because a DLN or other low-NO_X combustor has not yet been developed for

hydrogen-rich fuel, due to its high flame front speed and broad range of combustibility. When hydrogen-rich fuel is unavailable and during start-up/shut-downs, the HECA Project will fire natural gas for very limited periods as a backup fuel. The natural gas must be fired through the same diffusion burner because the MHI turbine does not have the option of a separate natural gas DLN combustor. Thus, the use of DLN combustor is not a technically feasible control option for this unit.

- Diluent Injection

  Higher peak flame temperature during combustion may increase thermodynamic efficiency, but it also increases the formation of thermal NO_X. The injection of an inert diluent such as atomized water, steam, or nitrogen into the high-temperature region of a combustor flame serves to inhibit thermal NO_X formation by reducing the peak flame temperature.

  For the Project's CTG/HRSG, nitrogen is used as a diluent that reduces thermal NO_X produced when hydrogen-rich gas is combusted. Steam is used as a diluent when natural gas is combusted. This method effectively lowers the fuel heat content, and consequently, the combustion temperature, thereby reducing NO_X emissions.

  A secondary benefit of diluent injection is that it will increase the mass flow of the exhaust. Therefore, the power output per unit of fuel input also increases.

  Diluent injection represents an inherently lower-emitting process for IGCC units, and is a technically feasible control technology. Diluent injection (steam for natural gas and nitrogen for hydrogen-rich fuel) is proposed as the baseline case for the CGT/HRSG combustion turbine NO_X BACT analysis. This NO_X control technology and emission level has also been determined as BACT for all other recent IGCC permits. This NO_X diluent injection control technology has been commercially demonstrated on syngas turbines.

- $SCONO_X$™

  The $SCONO_X$™ system is an add-on control device that reduces emissions of multiple pollutants. $SCONO_X$™ uses a single catalyst for the reduction of CO, VOC, and NO_X, which are converted to CO_2, water (H_2O), and nitrogen (N_2).

  All installations of the technology have been on small natural gas facilities, and have experienced performance issues. The fact that $SCONO_X$™ has not been applied to large-scale natural gas combustion turbines creates concerns regarding the timing, feasibility, and cost-effectiveness of necessary design improvements. $SCONO_X$™ has also not been applied to syngas (or hydrogen-rich fuel).

  In evaluating technical feasibility for large IGCC projects, the additional concerns are:

  – $SCONO_X$™ uses a series of dampers to re-route air streams to regenerate the catalyst. The HECA Project is significantly larger than the facilities where $SCONO_X$™ has been used. This would require a significant redesign of the damper system, which raises

feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the HECA CTG/HRSG.

– SCONO$_X$™ would not be expected to achieve lower guaranteed NO$_X$ levels than SCR, and, for reasons described above, it has even greater feasibility concerns with respect to application on IGCC turbines than those for SCR.

For the above reasons, SCONO$_X$™ is considered technically infeasible for this unit.

- Selective Non-Catalytic Reduction

Selective non-catalytic reduction is a post-combustion NO$_X$ control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with NO$_X$ to form elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO$_X$ emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas, which must occur within a narrow flue gas temperature zone (typically from 1,700 to 2,000 degrees Fahrenheit [°F]).

The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO$_X$. Below the lower end of the temperature range, the reagent will not react with the NO$_X$ resulting in very high ammonia slip concentrations (ammonia discharge from the stack).

This technology is occasionally used in conventional fired heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been applied in IGCC service, primarily because there are no flue gas locations within the combustion turbine or upstream of the HRSG with the optimal requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Therefore, SNCR is not technically feasible for this unit.

- Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is a technology that achieves post-combustion reduction of NO$_X$ from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of NO$_X$ to molecular nitrogen. SCR is a common control technology for use on natural gas–fired combustion turbines.

In the SCR process, ammonia, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the ammonia reacts with NO$_X$ to form molecular nitrogen and water. The basic reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

The Project selected SCR and diluent injection technology to control NO$_X$ emissions from the CTG/HRSG unit. Anhydrous ammonia is injected into the stack gases upstream of a

catalytic system that converts nitrogen oxide and ammonia to nitrogen and water. The SCR system reduces nitrogen oxide emissions from the HRSG stack gases by up to 92 percent when firing hydrogen-rich fuel, and up to 94 percent when firing natural gas. The maximum NO_X reductions that SCRs can typically achieve are 90 to 95 percent. HECA will optimize the SCR system to achieve NO_X reductions of this magnitude.

It is anticipated that this combination of control processes will achieve a NO_X emission limit of 2.5 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing hydrogen-rich fuel, or 4 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing natural gas.

The HECA Project has been designed to use steam injection and SCR for NO_X control when in natural gas service. A comparison with other recent IGCCs using SCR indicate that 4 ppm is an appropriate emission stack concentration for natural gas operation using a diffusion burner. (Note that the Hyperion Project's BACT limit for NO_X on natural gas is slightly lower than this, but uses DLN technology that is not available with syngas-fired turbines. Also, the Summit Project, when combusting natural gas, has a significantly higher short-term NO_X limit of 15 ppm, but a slightly lower long-term [30-day] rolling average limit; this is not comparable to the short-term limit proposed for HECA.) To provide the high level of confidence necessary to meet a 4 ppm permit limit, the HECA Project will plan to achieve very high conversion efficiency in the SCR. Therefore, the HECA LLC believes that the proposed 4 ppm NO_X level is an appropriate BACT level for the HECA Project when burning natural gas and is consistent with other recently permitted IGCCs.

These emission limitations for both hydrogen-rich fuel and natural gas represent a removal efficiency that is better than the approved emissions for recently permitted IGCC units. HRSG vendors confirm the feasibility of achieving these NO_X levels.

3. Rank Control Technologies

Among the control technologies considered in the previous subsection, only one was determined to be both technically feasible and commercially demonstrated at a cost level acceptable as a BACT option. Specifically, the feasible option is diluent injection upstream of the combustion zone.

Although there is no commercial demonstration of SCR performance for an IGCC plant using coal or petcoke feedstock, SCR technology has been proposed as emission limits for many recently permitted IGCC projects; therefore, SCR is determined to be technically feasible. The HECA HRSG vendor confirm that the SCR catalyst will be able to achieve combined NO_X reduction to 2.5 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing hydrogen-rich fuel, and 4 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing natural gas.

4. Evaluate Control Options

The next step in a BACT analysis is to evaluate the feasible control technology. Based on the evaluation in the previous step, the only feasible technologies suitable for establishment of

BACT limits are diluent injection and SCR. The principal environmental consideration with respect to implementation of SCR is that, while it will reduce NO_X emissions, it will add ammonia emissions associated with use of ammonia as the reagent chemical. A portion of the unreacted ammonia passes through the catalyst and is emitted from the stack. This is called ammonia slip, and the magnitude of these emissions depends on the catalyst activity and the degree of NO_X control desired. For the Project, the concentration of ammonia slip is limited to 5 ppmvd at 15 percent oxygen.

Table 6-2 shows the typical NO_X BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed NO_X BACT for the CTG/HRSG.

As shown in Table 6-2, the BACT limitation for NO_X emissions from HECA CTG/HRSG is more stringent than the historic BACT determination for other recently permitted IGCC projects.

NSPS 40 CFR 60 Subpart Da is considered as the BACT "floor" for this source category. As shown above, the BACT emission limit proposed for HECA is significantly lower than the applicable NSPS Subpart Da limit of 0.5 lb/MMBtu heat input for gaseous fuel. The proposed NO_X reduction technology is also more stringent than the NSPS Subparts Da recommended minimum reduction efficiency of 25 percent.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, for this application of hydrogen-rich fuel-fired combustion turbine within an IGCC facility, diluent injection in the combustion turbine and SCR installation as post-combustion NO_X control are the appropriate control techniques for setting BACT-based emission limits. The BACT selection described above is strongly supported by recent precedents for similar IGCC projects.

The proposed BACT limits based on this technology are 2.5 ppmvd NO_X at 15 percent oxygen for hydrogen-rich–fuel firing, and 4 ppmvd NO_X at 15 percent oxygen for natural-gas firing.

6.1.2 Carbon Monoxide BACT Analysis for the CTG/HRSG

CO is a product of incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. However, these same control factors can increase NO_X emissions. Conversely, lower NO_X emission rates achieved through flame temperature control (by diluent injection) can increase CO emissions for natural gas and un-shifted syngas. Thus, a compromise must be established whereby the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while keeping CO emissions to an acceptable level. However, CO emissions are inherently low for hydrogen-rich fuels that contain very little reduced carbon and are less affected by the conventional trade-off between CO and NO_X.

Table 6-2
NO_X BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	NO_X BACT Technology	Emission Limit on Syngas		Emission Limit on Natural Gas	
					ppmvd[b]	lb/MMBtu	ppmvd[b]	lb/MMBtu
HECA	CA	405	MHI 501 GAC®	SCR	2.5	0.011	4	0.015
Cash Creek Generation Station	KY	770	GE 7FB	SCR	5	0.0331	–	0.0246
Edwardsport Generating Station	IN	630 (net)	GE 7FB	SCR operated in trial mode	5	0.027[c]	–	0.018[c]
Taylorville Energy Center	IL	716	Siemens F Class; SNG fuel	DLN[d], SCR (SNG and natural gas)	2[d]	–	2	–
Hyperion Energy Center	SD	532	Not specified	Diluent Injection and SCR (syngas option) DLN and SCR (natural gas option)[e],	3[f]	0.018	2[g]	0.012
Kemper County IGCC Project	MS	582	Siemens 5000F	GCP and diffusion flame combustion (syngas); Steam/ Water Inject and SCR (natural gas)	–	0.061	–	0.015
Summit TCEP	TX	400	Siemens 5000F	Combustion control and SCR	15[h] 3.5[i]	0.014[i]	15[h] 2.5[i]	0.009[i]

Notes:
[a] MW represents gross power unless otherwise noted.
[b] ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2.
[c] Calculated from mass emissions rate of 57 lb/hr on hydrogen-rich fuel and 38 lb/hr on natural gas.
[d] DLN technology is feasible for substitute natural gas (SNG) – fired turbine. Emission limits are for SNG firing.
[e] For the syngas Option 1, diluent injection and SCR are proposed. DLN control will only be included if Option 2 is chosen, which is a natural gas-fired turbine with PSA tail gas fired only in the duct burner. These two options are mutually exclusive turbine configuration, one or the other will be selected, not a combination of the two.
[f] The DLN technology is not applied for this limit, as the technology is not feasible for a hydrogen-rich syngas-fired turbine.
[g] Emission limit for separate natural gas turbine option using DLN and SCR (see footnote e).
[h] Emission limit based on 1-hour averaging time.
[i] Emission limit based on 30-day averaging time.

DLN = dry low-NO_X burners
GCP = good combustion practice
MMBtu = million British thermal units
MW = megawatt
ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2
SCR = selective catalytic reduction

1. Identify Control Technologies

The following CO control technologies were evaluated for the proposed CTG/HRSG:

Combustion Process Controls

- Good Combustion Practices (GCPs)

Post-Combustion Controls

- $SCONO_X$™
- Oxidation Catalyst

2. Evaluate Technical Feasibilities

Good Combustion Practices

Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure optimum complete combustion. This technology has been determined to be BACT for CO emissions in other operational or recently permitted IGCC projects.

- $SCONO_X$™

  The $SCONO_X$ system was evaluated in the NO_X BACT analysis, and determined to be not technically feasible for this unit.

- Oxidation Catalysts

  Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize CO into CO_2. Other operational or recently permitted IGCC projects determined GCPs as the only feasible BACT for CO emissions, with the exception of the Hyperion Energy that is proposing use of an oxidation catalyst to reduce CO emissions to 3 ppm. HECA anticipates CO conversions greater than 90 percent are attainable across the CO catalyst, thus HECA proposed CO emission limits of 3 ppmvd at 15 percent oxygen while firing hydrogen-rich fuel, and 5 ppmvd CO at 15 percent oxygen while firing natural gas.

3. Rank Control Technologies

Oxidation catalyst is the only technically feasible CO control technology identified in addition to Good Combustion Practices.

4. Evaluate Control Options

GCP is considered the baseline and only feasible and commercially demonstrated CO control technology for IGCC combustion turbines. GCP has been selected as BACT for other recent

IGCC permits. The Hyperion Energy Center is the only IGCC project to propose use of oxidation catalysts to control CO. In comparison to other operational or recently permitted IGCC projects, this emission limitation represents a removal efficiency that is lower than the emission achieved in practice at currently operating IGCC turbines, and the lowest proposed emission limits for proposed syngas-fired units, including other proposed IGCC turbines.

Table 6-3 shows the typical CO BACT determination (when firing hydrogen-rich fuel and natural gas) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed CO BACT for the CTG/HRSG.

Table 6-3
CO BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	CO BACT Technology	Emission Limit on Syngas		Emission Limit on Natural Gas	
					ppmvd	lb/MMBtu	ppmvd	lb/MMBtu
HECA	CA	405	MHI 501 GAC®	Oxidation catalyst and GCP	3	0.008	5	0.011
Cash Creek Generation Station	KY	770	GE 7FB	GCP	–	0.0485	–	0.0449
Edwardsport Generating Station	IN	630 (net)	GE 7FB	GCP	–	0.0441[b]	–	0.0421[b]
Taylorville Energy Center	IL	716	Siemens MHI 501GAC® CT; SNG fuel	GCP	4.3[c]	–	4.3	–
Hyperion Energy Center	SD	532	Not specified	Oxidation catalyst and GCP	3	–	3[d]	–
Kemper County IGCC Project	MS	582	Siemens 5000F	GCP	–	0.031	–	0.063
Summit TCEP	TX	400	Siemens 5000F	GCP	10	0.02	10	0.02

Notes:
[a] MW represents gross power unless otherwise noted.
[b] Calculated from mass emissions rate of 93 lb/hr on hydrogen-rich fuel and 88.7 lb/hr on natural gas.
[c] Emission limit for substitute natural gas (SNG) – fired turbine; turbines are set up for natural-gas type of firing only.
[d] Emission limit for separate natural gas turbine option set up with CO catalyst and GCP specifically for natural gas use. The natural gas turbine option is a mutually exclusive turbine configuration from the syngas Option 1, only one turbine configuration will be selected, not a combination of the two.

GCP = good combustion practice
lb/MMBtu = pound per million British thermal units
MW = megawatt
ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2.

As shown in Table 6-3, the BACT limitation for CO emissions from HECA CTG/HRSG is more stringent than most of the historic BACT determination for other recently permitted IGCC units. This emission limitation represents a removal efficiency that is better than the emission achieved in practice at currently operating IGCC turbines, and equals the lowest proposed emission limits for recently permitted IGCC turbines. The proposed CO emission limit for backup natural gas firing is lower than other similarly operated units. It is slightly higher than the limits proposed for Taylorville and Hyperion; turbines at both of these facilities are designed specifically for natural gas firing as the primary fuel, not as a backup, as is the case for HECA.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and oxidation catalyst are the appropriate control technique for setting BACT-based emission limits.

HECA proposed the CO BACT-based limit of 3 ppmvd at 15 percent oxygen while firing hydrogen-rich fuel, and 5 ppmvd CO at 15 percent oxygen while firing natural gas during non-start-up operation, using GCPs and an oxidation catalyst.

6.1.3 Particulate Matter Emissions BACT Analysis for the CTG/HRSG

Particulate matter emissions from gas-fired combustion sources consist of inert contaminants in gaseous fuel, sulfates from fuel sulfur, ammonia compounds for the SCR reagent, dust drawn in from the ambient air that passes through the combustion turbine inlet air filters, and particles of carbon and hydrocarbons resulting from incomplete combustion. Low ash content and high combustion efficiency exhibit correspondingly low particulate matter emissions for hydrogen-rich fuel.

1. Identify Control Technologies

The following particulate matter control technologies were evaluated for the proposed CTG/ HRSG:

Pre-Combustion Controls

- Gas Cleanup (for hydrogen-rich fuel)

Combustion Process Controls

- Good Combustion Practices

Post-Combustion Controls

- Baghouse
- Electrostatic Precipitation

2. Evaluate Technical Feasibilities

In a typical solid fuel combustion process, fuel particulate matter is removed by post-combustion processes such as fabric filters or electrostatic precipitators. However, in an IGCC plant, particulate matter could damage the turbine, so particulate matter is removed prior to combustion. Post-combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial combustion turbines burning gaseous fuels. Therefore, the use of ESPs and baghouses are considered technically infeasible control technology.

In the absence of add-on controls, the most effective control method demonstrated for gas-fired combustion turbines is the use of low-ash fuel, such as natural gas or hydrogen-rich fuel and GCPs. Therefore, it is necessary to use pre-combustion controls such as particulate removal as an integral part of the gasification process, in addition to GCPs.

The use of clean hydrogen-rich fuel and good combustion control is proposed as BACT for PM/ PM_{10} control in the proposed HECA CTG/HRSG. These operational controls will limit filterable plus condensable PM/PM_{10} emissions to 15 lb/hr when operating on hydrogen-rich fuel or natural gas.

3. Rank Control Technologies

The use of clean fuels with low potential particulate emissions from optimum gas cleanup processes and GCPs were identified as the only technically feasible particulate emissions control technologies applicable to the proposed combustion turbines.

4. Evaluate Control Options

The USEPA has indicated that particulate matter control devices are not typically installed on combustion turbines and that the cost of installing a particulate matter control device is prohibitive. When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the USEPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the recently revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for particulate matter control of stationary gas turbines have not been proposed or promulgated at a federal level.

Table 6-4 shows the typical PM BACT determination (when firing hydrogen-rich fuel and natural gas) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed PM BACT for the CTG/HRSG.

Based on the evaluation in the previous step, GCPs and optimum gas cleanup are considered as technically feasible PM/PM_{10} control technologies that are suitable for establishment of BACT limits. As shown in Table 6-4, HECA emission limitation represents a removal efficiency that is cleaner in comparison to other operational or recently permitted IGCC units. Therefore, the BACT limitation for PM emissions from HECA CTG/HRSG is more stringent than the historic BACT determination for other recently permitted IGCC units.

Table 6-4
PM BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	PM_{10} BACT Technology	Emission Limit on Syngas (lb/hr)	Emission Limit on Natural Gas (lb/hr)
HECA	CA	405	MHI 501 GAC®	Gas Cleanup and GCP	15 (0.008 lb/ MMBtu)	15 (0.008 lb/ MMBtu)
Cash Creek Generation Station	KY	770	GE 7FB	Gas Cleanup and GCP	76[b]	57[b]
Edwardsport Generating Station	IN	630 (net)	GE 7FB	Gas Cleanup and GCP	63[b]	29[b]
Taylorville Energy Center	IL	716	Siemens MHI 501GAC® CT; SNG fuel	GCP	0.0065 lb/ MMBtu[c]	0.0065 lb/ MMBtu
Hyperion Energy Center	SD	532	Not specified	AGR, Rectisol®	36.9 (0.022 lb/ MMBtu)	18.4 (0.011 lb/ MMBtu)[d]
Kemper County IGCC Project	MS	582	Siemens 5000F	Clean fuels and GCP	36[b]	0.01 lb/MMBtu
Summit TCEP	TX	400	Siemens 5000F	Clean fuels and GCP	0.008 lb/MMBtu	0.008 lb/ MMBtu

Notes:

[a] MW represents gross power unless otherwise noted.

[b] Emission limits have been prorated to HECA-sized turbine in MW for comparison purposes. This is only done in cases where no other limits (such as lb/MMBtu) are provided.

[c] Emission limit using substitute natural gas (SNG); turbines are set up for natural-gas type firing only.

[d] Emission limit for separate natural gas turbine option specifically for natural gas use.

AGR = acid gas removal
lb/MMBtu = pound per million British thermal unit
MW = megawatt
PM_{10} = particulate matter 10 microns in diameter or less

NSPS 40 CFR 60 Subpart Da is considered as the BACT "floor" for this source category. The BACT emission limits proposed in Table 6-4 are equivalent to 0.006 lb/MMBtu on hydrogen-rich fuel, and 0.006 lb/MMBtu on natural gas. These emission limits are significantly lower than the applicable NSPS Subpart Da limit of 0.03 lb/MMBtu heat input derived from the combustion of solid, liquid, or gaseous fuel.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and optimum gas cleanup are the appropriate control technique for setting BACT-based emission limits. The use of optimum gas cleanup to produce clean fuels with low potential particulate emissions and GCPs were selected as LAER for particulate emissions from the proposed combustion turbines. The following emission limit resulting from the implementation of these technologies is proposed for each combustion turbine.

HECA proposed the PM BACT-based limit of 15 lb/hr while firing hydrogen-rich fuel or natural gas, during non-start-up operation, using GCPs and optimum gas cleanup.

6.1.4 Sulfur Dioxide and Sulfuric Acid Mist BACT Analysis for the CTG/HRSG

Sulfur dioxide emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel usage. The combustion of hydrogen-rich fuel in the combustion turbines creates primarily SO_2 and small amounts of sulfite (SO_3) by the oxidation of the fuel sulfur. The SO_3 can react with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Emissions of these sulfur species can be controlled, either by limiting the sulfur content of the fuel (pre-combustion control), or by scrubbing the SO_2 from the exhaust gas (post-combustion control).

1. Identify Control Technologies

The following sulfur dioxide and sulfuric acid mist control technologies were evaluated for the proposed CTG/HRSG when operating on hydrogen-rich fuel:

Pre-Combustion Controls

- Chemical Absorption Acid Gas Removal (AGR), e.g., methyldiethanol-amine (MDEA)
- Physical Absorption Acid Gas Removal, e.g., Selexol®, Rectisol®

Post-Combustion Controls

- Flue Gas Desulfurization

The sulfur dioxide BACT for the proposed CTG/HRSG when operating on natural gas is PUC-grade natural gas fuel with less than 0.75 grain/100 scf sulfur content.

2. Evaluate Technical Feasibilities

- Acid Gas Removal

  In the gasification process, sulfur in the petcoke or coal feedstock converts primarily to hydrogen sulfide (H_2S). Solvent-based acid gas cleanup is commonly used for "gas sweetening" processes in petroleum refinery fuel gas or tail gas treating units, where H_2S in

the process gas is removed before use as a fuel. The removed H_2S is recovered either as elemental sulfur in a Sulfur Recovery Unit (e.g., using a Claus process).

In a chemical absorption process, acid gases in the sour syngas are removed by chemical reactions with a solvent that is subsequently separated from the gas and regenerated. The chemical absorption occurs in amine-based systems that use solvents such as MDEA. Amine solvents chemically bond with the H_2S. The H_2S can be easily liberated with low-level heat in a stripper to regenerate the solvent. However, amine-based systems such as MDEA are not effective at removing COS and have not demonstrated the deep total sulfur removal levels required by the Project.

Lower levels of sulfur removal are possible using physical absorption AGR systems. Physical absorption methods, including Selexol® and Rectisol®, use solvents that dissolve acid gases under pressure. Selexol® or Rectisol® are normally applied when low syngas sulfur levels are required for SCR. Solubility of an acid gas is proportional to its partial pressure and is independent of the concentrations of other dissolved gases in the solvent. Consequently, increased operating pressure in an absorption column facilitates separation and removal of an acid gas like H_2S. The dissolved acid gas can then be removed from the solvent, which is regenerated by depressurization in a stripper.

To selectively remove H_2S and CO_2, two absorption and regeneration columns or two-stage process are required. In general, H_2S is selectively removed in the first column by a lean solvent that has been deeply stripped with steam, while CO_2 is removed from the now H_2S-free gas in the second absorber. The second-stage solvent can be regenerated if very deep CO_2 removal is required. If only bulk CO_2 removal is required, then the flashed gas containing the bulk of the CO, can be vented, and the second regenerator duty can be substantially lowered or totally eliminated.

- Flue Gas Desulfurization

Flue gas desulfurization (FGD) is a post-combustion SO_2 control technology that reacts an alkaline with SO_2 in the exhaust gas. Typical FGD processes operate by contacting the exhaust gas downstream of the combustion zone with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry, based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes that use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent are the most common FGD systems in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and discharged through a stack.

Flue gas desulfurization systems are commonly employed in conventional PC plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95 percent sulfur removal. However, FGD cannot provide as high a level of control as the pre-combustion AGR systems. In addition, FGD has the environmental drawbacks of substantial water usage

and the need to dispose of a solid byproduct (the scrubber sludge). The solid by-product requires the installation of a significant number of ancillary support systems to accommodate treatment, handling, and disposal. Given these disadvantages and the fact that FGD could not achieve the high removal efficiencies associated with AGR, even though FGD is not technically infeasible, it is not considered to be a reasonable technical option for IGCC. Therefore FGD will not be considered further in this BACT analysis

3. Rank Control Technologies

Both chemical and physical absorption methods for AGR are considered feasible for an IGCC, and can achieve control of the sulfur in syngas up to 99 percent or better. Both of these systems are further considered in the BACT analysis.

4. Evaluate Control Options

Physical absorption AGR systems (including Selexol® and Rectisol®) are considered as feasible sulfur dioxide and sulfuric acid mist control technology for the proposed CTG/HRSG turbine. Selexol® has been selected as BACT for several of the recent IGCC permits. Rectisol® was selected for Taylorville Energy Center and the Hyperion Energy Project and has also been widely used in gasification projects in the chemical industry where both deep sulfur removal and CO_2 removal are required. Both Rectisol® and Selexol® are considered viable alternatives to MDEA. However, the Project selected Rectisol® because there are more units operating at similar capacities and similar conditions to those required for the Project, making Rectisol® the more proven alternative.

Table 6-5 shows the typical SO_2 BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed SO_2 BACT for the CTG/HRSG.

As shown in Table 6-5, the BACT limitation for SO_2 emissions from HECA CTG/HRSG when firing hydrogen-rich fuel is similar to the historic BACT determination for other recently permitted IGCC units. This emission limitation represents a removal efficiency that is better than the emission achieved in practice at currently operating IGCC units, and similar to the proposed emission limits compared to recently permitted IGCC units.

NSPS 40 CFR 60 Subpart Da is considered as the BACT "floor" for this source category. The proposed SO_2 emission limits are significantly lower than the applicable NSPS Subpart Da limit of 180 nanograms per joule (1.4 lb/MWh) or 95 percent reduction on a 30-day rolling average.

When firing natural gas, SO_2 emission from CTG/HRSG is slightly higher than other recently permitted IGCC units. The SO_2 BACT for the proposed CTG/HRSG when operating on natural gas is PUC-grade natural gas fuel with less than 0.75 grain/100 scf sulfur content.

Table 6-5
SO_2 BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	SO_2 BACT Technology	Emission Limit on Syngas		Emission Limit on Natural Gas	
					ppm	lb/MMBtu	ppm	lb/MMBtu
HECA	CA	405	MHI 501 GAC®	AGR, Rectisol®	≤ 2 ppm Sulfur in undiluted Hydrogen-rich fuel ≤ 10 ppm Sulfur in PSA off-gas	0.0002	0.75 grains/ 100 scf	0.002
Cash Creek Generation Station	KY	770	GE 7FB	AGR, Selexol®	3.8[b]	0.0158		0.0006
Edwardsport Generating Station	IN	630 (net)	GE 7FB	AGR, Selexol®		0.0138[c]		0.0006[c]
Taylorville Energy Center	IL	716	Siemens MHI 501GAC® CT; SNG fuel	AGR, Rectisol®	0.25 grains/ 100 scf in SNG	–	0.25 grains/ 100 scf	–
Hyperion Energy Center	SD	532	Not specified	AGR, Rectisol®	1 ppmv Sulfur in syngas[d]; 0.5 ppmv in PSA off-gas	0.0005[d]	9 ppmv	–
Kemper County IGCC Project	MS	582	Siemens 5000F	AGR, Selexol®	–	0.004		1.9 lb/hr
Summit TCEP	TX	400	Siemens 5000F	Low Sulfur fuel	10 ppmv Sulfur in Syngas	0.006	2 grains/ 100 dscf	0.006

Notes:
[a] MW represents gross power unless otherwise noted.
[b] Parts per million by volume, dry basis, corrected to 15 percent O_2.
[c] Calculated from mass emissions rate of 2.9 lb/hr on hydrogen-rich fuel and 1.30 lb/hr on natural gas.
[d] Emission limit based on 24-hr rolling average.

AGR = acid gas removal
dscf = dry standard cubic foot
lb/MMBtu = pounds per million British thermal units
MW = megawatt
ppm = parts per million
ppmv = parts per million by volume
scf = standard cubic foot
SNG = substitute natural gas

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. HECA selected Rectisol® as the syngas cleanup control technology to remove sulfur dioxide from the hydrogen-rich fuel stream entering the CTG/HRSG. The reduction efficiency of Rectisol® is above the NSPS floor requirement, and the overall performance of this technology is more stringent than the historic BACT determination for other recently permitted IGCC units. The following emission limit resulting from the implementation of these technologies is proposed for each combustion turbine.

HECA proposed the SO_2 BACT-based limit of ≤ 2 ppmv sulfur in undiluted hydrogen-rich syngas, ≤ 10 ppmv sulfur in PSA off-gas using an AGR system (Rectisol®) and ≤0.75 grains/ 100 scf of natural gas sulfur content using PUC-grade natural gas. These levels will meet the SJVAPCD BACT guideline 7.2.6 for sulfur recovery plants.

6.1.5 Volatile Organic Compounds BACT Analysis for the CTG/HRSG

VOCs are a product of incomplete combustion of the organic components in the hydrogen-rich fuel. Hydrogen-rich fuel contains very low concentrations of VOC; therefore, emissions of VOC are inherently very low. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to ensure complete combustion. A survey of the RBLC database indicated that good combustion control and burning clean gas fuel are the VOC control technologies primarily determined to be BACT. The advantage of IGCC technology is the fact that the combustion turbine operates on hydrogen-rich fuel, which contains a very low organic content, and yields very low levels of uncombusted VOC emissions.

1. Identify Control Technologies

The following VOC control technologies were evaluated for the proposed CTG/HRSG:

Combustion Process Controls

- Good Combustion Practices

Post-Combustion Controls

- $SCONO_X$™
- Oxidation Catalyst

2. Evaluate Technical Feasibilities

- Good Combustion Practices

  GCPs include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure optimum complete combustion.

This technology has been determined to be BACT for VOC emissions in other operational or recently permitted IGCC projects.

- $SCONO_X$™

  The $SCONO_X$ system was evaluated in the NO_X BACT analysis, and determined to be not technically feasible for this unit.

- Oxidation Catalysts

  Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize VOC. The catalyst beds that functions to reduce CO emissions can also be effective in reducing VOC emissions. Such systems typically achieve a maximum VOC removal efficiency of up to 50 percent, while providing control for CO.

  Other operational or recently permitted IGCC projects determined GCPs as the only feasible BACT for VOC emissions, with the exception of the Hyperion Energy that is proposing use of an oxidation catalyst to reduce VOC emissions. The turbine exhaust will achieve VOC emission levels of 1.0 ppmvd VOC (at 15 percent oxygen) when firing hydrogen-rich fuel, and 2.0 ppmvd VOC (at 15 percent oxygen) when operating on natural gas.

3. Rank Control Technologies

Oxidation catalyst is the only technically feasible VOC control technology identified in addition to GCPs.

4. Evaluate Control Options

GCPs are considered the baseline and the only commercially demonstrated VOC control technology for IGCC combustion turbines. GCP has been selected as BACT for all other recent IGCC permits, with the exception of the Hyperion Energy, that is proposing use of an oxidation catalyst. In comparison to other operational or recently permitted IGCC projects, this emission limitation represents a removal efficiency that is lower than the emissions achieved in practice at currently operating IGCC units, and the lowest proposed emission limits for proposed turbines combusting syngas.

Table 6-6 shows the typical VOC BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed VOC BACT for the CTG/HRSG.

As shown in Table 6-6, the BACT limitation for VOC emissions from HECA CTG/HRSG is comparable to the historic BACT determination for other recently permitted IGCC turbines when firing syngas. This emission limitation represents a removal efficiency that is as good as the emissions proposed in recently permitted syngas turbines.

Table 6-6
VOC BACT Emission Limit Comparison

Facility	State	MW[a]	Turbine	VOC BACT Technology	Emission Limit on Syngas		Emission Limit on Natural Gas	
					ppmvd	lb/MMBtu	ppmvd	lb/MMBtu
HECA	CA	405	MHI 501 GAC®	Oxidation catalyst and GCP	1	0.0015	2	0.003
Cash Creek Generation Station	KY	770	GE 7FB	GCP	–	N/A	–	N/A
Edwardsport Generating Station	IN	630 (net)	GE 7FB	GCP	–	0.0016[b]	–	0.0016[b]
Taylorville Energy Center	IL	716	Siemens MHI 501GAC® CT; SNG fuel	GCP	–	0.0013[c]	–	0.0013
Hyperion Energy Center	SD	532	Not specified	Oxidation catalyst and GCP	–	0.0017	–	0.0017[d]
Kemper County IGCC Project	MS	582	Siemens 5000F	GCP	–	0.005	–	0.008
Summit TCEP	TX	400	Siemens 5000F	GCP	1	0.0012	1	0.0012

Notes:
[a] MW represents gross power unless otherwise noted.
[b] Calculated from mass emissions rate of 3.3 lb/hr on hydrogen-rich fuel and natural gas.
[c] Emission limit using substitute natural gas (SNG); turbines are set up for natural-gas type of firing only.
[d] Emission limit for separate natural gas turbine option set up with CO catalyst and GCP specifically for natural gas use. The natural gas turbine option is a mutually exclusive turbine configuration from the syngas Option 1, only one turbine configuration will be selected, not a combination of the two.

GCP = good combustion practice
lb/MMBtu = pound per million British thermal units
MW = megawatt
ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2.
VOC = volatile organic compound

The proposed VOC emission limit for backup natural gas firing is comparable to other similarly operated units, although it is slightly higher than the limits proposed for Taylorville and Hyperion; turbines at both of these facilities are designed specifically for natural gas firing as the primary fuel, not as a backup, as is the case for HECA. The Summit Project, when combusting natural gas, has a slightly lower long-term average limit than HECA is proposing, although this is not comparable to the short-term limit proposed for HECA.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and oxidation catalyst are the appropriate control technique for setting BACT-based emission limits.

HECA proposes the VOC BACT-based limit of 1.0 ppmvd at 15 percent oxygen while firing hydrogen-rich fuel, and 2.0 ppmvd VOC at 15 percent oxygen while firing natural gas during non-start-up operation, using GCPs and oxidation catalyst.

6.1.6 Startup and Shutdown BACT Analysis for the CTG/HRSG

The proposed turbine is a MHI 501 GAC® model turbine with a gross capacity of approximately 405 MW, operating in a combined cycle mode and discharging its exhaust gases through a HRSG. The MHI 501 GAC® turbine is a new turbine model designed for optimum performance on both hydrogen-rich fuel and natural gas and includes changes to the fuel system, combustion system and hot gas path to accommodate this combination of fuels.

According to the turbine manufacturer, the emissions of all criteria pollutants except SO_2 and PM_{10} will be slightly higher during turbine start-up. This is in part due to lower control effectiveness of the SCR and Oxidation Catalyst control systems until the exhaust gases reach optimal operating temperatures. This is also due to the slightly lower combustion efficiency of gas turbines at low loads, particularly during cold starts. Consequently, the most effective consideration for minimizing emissions due to start-up and shutdown events is to minimize the frequency and duration of these events.

HECA is being designed and permitted as a base-load electrical generating facility. In keeping with this mode of operation, frequent start-ups and shut-downs of the combustion turbine and HRSG will not be required. In contrast, a NGCC plant may frequently be turned off during periods of low demand (e.g., overnight). The time required for gasifier start-up does not allow overnight shut-downs (and would also result in some flaring during each event). The Project proposed maximum annual start-up and shut-down duration of 314 hours per year for the entire facility and 123 hours per year for the CTG/HRSG. This limit would allow 2 starts per year for HECA, as compared to a typical NGCC plant that may be allowed up to 250 starts per year.

The estimated annual criteria pollutant emissions for the CTG/HRSG operating scenario, including start-up/shut-down emissions and maximum permitted natural gas backup operation, are presented below in Table 6-7.

Table 6-7
Maximum Annual Emissions from the CTG/HRSG

Pollutant	Startup and Shutdown Emissions (ton/yr)	CTG/HRSG Emissions Hydrogen-Rich Fuel (tons/yr)	CTG/HRSG Emissions Natural Gas (tons/yr)	Maximum Total CTG/HRSG Emissions (tons/yr)
NO_X	4.3	99.6	5.7	109.7
CO	15.7	72.8	4.4	92.9
VOC	0.5	13.9	1.0	15.3
PM_{10}	0.8	51.3	2.5	54.6
SO_2	0.1	16.2	0.8	17.1
NH_3	0.0	73.6	2.6	76.3

The start-up and shut-down emissions basis included in the above annual emissions estimate are based on the 2 start-ups and 2 shut-downs per year. The emissions from these events represent a very small percentage of the overall Project emissions. For example, NO_X emissions from start-up and shut-down of this base-load turbine would be approximately 4 percent of the total annual turbine emissions. VOC, PM, and SO_2 emissions vary from approximately 1 to 3 percent of the annual turbine emissions. CO emissions are somewhat larger, but still represent less than 20 percent of the annual emissions. This sharply contrasts with single-cycle peaking turbine permits, where start-up emissions can represent the majority of a facility's permitted emissions for certain pollutants.

The following sections provide a stepwise evaluation of control technologies considered for BACT for the proposed CTG/HRSG.

1. Identify Control Technologies

A review of the RBLC database for large combustion turbines in the last 10 years identified only a few combustion turbine entries that specifically discuss start-up or shut-down emissions. Only two of these entries listed the emissions control method determined to represent BACT for start-up emissions, as shown below.

RBLC ID:	LA-0224
+Corporate/Company Name:	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)
+Facility Name:	ARSENAL HILL POWER PLANT
Facility State:	LA
+Control Method Description:	**COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURE'S RECOMMENDED PROCEDURES**

RBLC ID:	IN-0115
+Corporate/Company Name:	MIRANT SUGAR CREEK, LLC
+Facility Name:	MIRANT SUGAR CREEK, LLC
Facility State:	IN
+Control Method Description:	**DRY LOW-NOX BURNERS, GOOD COMBUSTION PRACTICES, NATURAL GAS.**

None of the combustion turbines with start-up and shut-down entries in the RBLC are in IGCC service. Nevertheless, their identified start-up and shut-down BACT listings are helpful references for possible emission control ideas.

Because precedents established in the permits of similar projects can be relevant in determining BACT, the permits for several recent IGCC projects were also reviewed. The following three examples summarize the relevant control strategies identified in other IGCC permits.

Hyperion Energy Center IGCC – Requirement for startup and shutdowns as referenced from this PSD permit are as follows; "…the owner or operator shall use good work and maintenance practices and manufacturers' recommendations to minimize emissions during, and the frequency and duration of, startup, shutdown, and malfunction events for those units and pollutants that are not using a continuous emissions monitoring system to demonstrate compliance. The owner or operator shall develop and implement a startup, shutdown, and malfunction plan…."

Duke Edwardsport IGCC – "Emissions from startups and shutdowns of the power block of the IGCC plant shall not exceed the established annual and 24-hour average limits determined on a monthly basis, using the appropriate emission factors and number of specific startup and shutdown events per month."

Cash Creek IGCC – "…at all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source."

Based on the above review, and also including the "fast-start" and "opflex" technologies mentioned by USEPA, the following start-up/shut-down (SU/SD) control technologies were evaluated for the proposed CTG/HRSG:

Combustion Process Controls

1) Fast Start and OpFlex Technology

2) Several aspects of Good Air Pollution Control Work Practices (i.e., Complete events as quickly as possible following manufactures recommendation and or Startup, Shutdown or Malfunction Plans)

2. Evaluate Technical Feasibilities

Fast Start and OpFlex Technology

The proposed combustion turbine, the MHI 501 GAC®, is designed to run as a combined-cycle turbine specifically for IGCC applications. The "fast start" or "opflex" technologies are technologies that suppliers such as GE offer for their combustion turbines. The technology consists of specialized control software that allows a slightly more rapid start-up and slightly lower turndown level on turbines. The concept is to bring the CTG into emissions compliance quicker during the start-up of a NGCC. This approach minimizes the higher emission rates

associated with lower load operation, while providing adequate temperature control of the steam entering the steam turbine generator (STG). Plants that are currently using this system or are slated to employee it use DLN combustion technology. Furthermore, these facilities are generally in peaking service, where there are numerous hot and cold starts per year.

The GE OpFlex(TM) system has limited field operating experience in NGCC facilities and no experience in a facility designed to operate on hydrogen fuel. The differences between NGCC and hydrogen fueled IGCC facilities are substantial. Although the GE OpFlex(TM) is an innovative technology that has been successfully applied for NGCC operation, it has not been proven for application in a hydrogen fueled facility like HECA. For this reason, and because the HECA Project is a base-loaded facility with start-up emissions that are a relatively small portion of the total CTG/HRSG emissions, additional BACT for start-up and shut-down should not be required.

Good Air Pollution Control Work Practices

Good air pollution control work practices are feasible for the Project. The proposed CTG for the HECA Project is designed to minimize the frequency and duration of start-up and shut-down events by using the following work practices, operating controls, and design elements:

- Baseload Power Generation Project (inherent design feature)
- Use of fuel dilution, SCR and CO catalyst systems during start-up and shut-down when operating conditions are amenable to their effective use.
- Follow manufacturer's recommendations to minimize the duration and emissions during start-up.

The Project will be operated as a base-load power generating unit. Unlike peak-load generation, base-load power generation entails continuous operation and power generation during all seasons that is normally interrupted only for maintenance or unexpected outages. The applicant is proposing a maximum of only two start-ups annually to allow for repairs and/or maintenance activities. In contrast, a peak-load plant may operate only several hours per day (during periods of peak electrical demand).

Another operating control/design element of the Project that inherently minimizes the emissions associated with start-up and shut-down events from the CTG/HRSG is the use of fuel dilution, SCR and CO catalyst systems. The primary purpose of these emissions controls is to control emissions during operations. However, they will provide some benefit during start-up and shut-down as well. For example, the SCR and CO catalyst systems will be in the direct path of the exhaust flow throughout the start-up and shut-down processes. As described in the permit application, the oxidation catalyst will be in service and functioning to provide emissions control as soon as the CTG/HRSG operating temperature rises to a sufficient level. Meaningful control of CO emissions by the oxidation catalyst should begin as the temperature approaches about 400 ºF. The SCR catalyst system will be in the exhaust gas flow path throughout start-ups, but will become effective for NO_X control when both the temperature is sufficient (about 450 to 500 ºF) to activate the ammonia injection system. Injection of ammonia prematurely will cause excessive ammonia slip. HECA plans to begin injection of ammonia as soon as the exhaust gas

operating conditions are amenable to its effective use, following manufacturers' recommendations.

In addition to the above aspects, HECA will follow manufacturers' recommendations and good work practices to minimize the numbers and durations of start-ups and shut-downs and, hence the emissions associated with non-routine operation.

3. Rank Control Technologies

Among the potentially available controls, the only feasible and commercially demonstrated control technology for IGCC combustion turbines start-up and shutdown is the use of good air pollution control practices to minimize emissions during start-up and shutdown.

4. Evaluate Control Options

The only feasible and commercially demonstrated control technology for IGCC combustion turbines start-up and shut-down is the use of good air pollution control practices to minimize emissions during start-up and shut-down.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps and review of determinations for turbine start-ups and shut-downs of other IGCC projects. As a result of these considerations, BACT for the HECA Project's turbine start-up and shut-down emissions is proposed as follows:

1. HECA shall operate the CTG/HRSG using good work practices and following manufacturers' recommendations to minimize emissions during, and the duration of, start-up and shut-down events.

2. CTG/HRSG exhaust will be routed through the SCR system and the oxidation catalyst system at all times including periods of start-up and shut-down. Ammonia shall be added to the SCR system when operating conditions are amenable to its effective use.

3. HECA shall monitor and maintain records of each start-up and shut-down event including the duration of the event.

4. HECA shall include the emissions during periods of start-up and shut-down, along with routine emissions, in determining compliance with the long-term annual emission rates which were used in the permit modeling demonstration.

6.2 Coal Dryer BACT Analysis

The MHI gasifier is a completely enclosed process with only one emission point: the coal dryer. This system uses dry feed in an oxygen-blown gasifier to generate the raw syngas. This syngas

is further treated in the downstream units to produce the hydrogen used for the combined cycle unit fuel as well as feed for the Manufacturing Complex. This technology has no start-up emissions directly from the gasifier. Waste gases from gasifier warming, start-up, and shut-down are routed to the one of the flares for safe disposal (which are discussed in later sections of this analysis).

The coal (feedstock) dryer removes moisture from the solid feed to ensure proper grinding and injection into the gasifier. The coal dryer is the only emission point associated with the gasifier system. The heat source for the dryer is a slipstream of HRSG fluegas. This slipstream is obtained just downstream of the catalytic emission controls (SCR and CO catalysts described above) and is ducted to the coal dryer adjacent to the gasifier. The coal dryer is a totally enclosed vessel that contacts the hot flue gas with the coal/petcoke feed material as it enters the grinder. After drying the solid feed, the flue gas is routed to the coal dryer vent stack. The vented gas will contain the moisture removed from the feed, the residual emissions from the HRSG emission controls, and particulate fines entrained from the solid feed. Baghouse fabric filtration will be provided on this vent stream to reduce the particulate emissions to less than 0.001 grain/dscf.

Because the HRSG fluegas has already undergone emission controls for NO_X, CO and VOC, only BACT for PM is reviewed, as emissions of PM are primarily due to the particulate fines entrained from the solid feed in the flue gas, as a consequence of the direct-contact drying process. Even though it is expected that most of these entrained particles are larger than PM_{10}, the controls discussed below apply to PM_{10} and $PM_{2.5}$ as well. An RBLC search for coal dryers identified three units; two of these have baghouses as BACT and one has a fabric filter (essentially the same technology as a baghouse). Baghouses (fabric filtration) are considered to be the only applicable control technology for PM/PM_{10} from coal dryers. The BACT limits cited for the three units range from 0.01 to 0.015 gr/dscf for filterable PM. The baghouse selected for the HECA coal dryer is designed to limit PM emissions to 0.001 gr/dscf. Therefore, HECA proposes this baghouse efficiency as the BACT for the coal dryer vent.

6.3 Cooling Towers Particulate Emissions BACT Analysis

There will be three cooling towers proposed for the Project: two cooling towers, the process cooling tower and the Air Separation Unit (ASU) cooling tower, are associated with the gasification process and Manufacturing Complex, and the third cooling tower, the power block cooling tower, is used by the power block. Compared to similar sized combined cycle power plants, the power block cooling duty is somewhat greater due to the heat integration with gasification resulting in the generation of additional steam for power production in the steam turbine and therefore requires additional cooling to condense this steam from the gasification block. Each tower has a separate cooling water basin, pumps, and piping system, and operates independently. The cooling water will circulate through a mechanical draft-cooling tower that uses electric motor-driven fans to move the air into contact with the flow of the cooling water. The heat removed in the condenser will be discharged by heating the air, and through evaporation of some of the cooling water.

The power block cooling tower is designed for an approximate capacity of 95,500 gallons per minute (gpm) of water, the process cooling tower design circulation rate is 162,582 gpm, and the ASU cooling tower design circulation rate is 44,876 gpm.

All cooling towers are supplied with high-efficiency drift eliminators designed to reduce the maximum drift; that is, the fine mist of water droplets entrained in the warm air leaving the cooling tower, to less than 0.0005 percent of the circulating water flow. Circulating water could range in total dissolved solids (TDS) depending on makeup-water quality and tower operation. Therefore, PM_{10} emissions would vary proportionately.

For cooling water makeup uses, HECA will use local brackish groundwater that has been determined by the local water district to be impaired and not suitable for agricultural or drinking use without extensive treatment because of its high TDS content. These impaired groundwater sources are found in various locations within the BVWSD Buttonwillow Service Area. According to the BVWSD, the impaired groundwater is considered objectionable by local agricultural users because it is unsuitable for good crop yield or crop diversification. As such, this water currently poses a negative impact on agriculture. Elevated TDS in groundwater has prompted the BVWSD to develop the Brackish Groundwater Remediation Project. This program includes extraction of groundwater in elevated TDS areas. HECA's use of this poor quality groundwater for the proposed Project's process water needs will remove significant TDS from the groundwater aquifer and is consistent with the BVWSD groundwater remediation plan. The maximum cycled-up cooling water TDS for the process and power block cooling tower will be 9,000 parts per million by weight (ppmw) and 2,000 ppmw for the ASU cooling tower.[2]

Wet (evaporative) cooling towers emit aqueous aerosol "drift" particles that evaporate to leave crystallized solid particles that are considered PM_{10} emissions. The proposed control technology for PM_{10} is high-efficiency drift eliminators to capture drift aerosols upstream of the vent point.

1. Identify Control Technologies

The following particulate matter control technologies were evaluated for the proposed cooling towers:

Potential Cooling Tower Control Technology

- Air Cooled Condenser (ACC) Technology
- Drift Elimination System with limited TDS level

[2] The cooling equipment in the ASU requires significantly lower dissolved solids in the circulating water than the rest of the plant.

2. Evaluate Technical Feasibilities

- Air Cooled Condenser Technology

Although most power plants and other industrial processes are cooled by use of non-contact cooling water, some use air cooling systems which directly reject heat to the air. Air cooled plants employ high-flow forced draft fans to blow air across a system of finned tubes in the condenser through which the steam (or process fluid needing cooling) passes. The heat from the process is simply transferred to the ambient air directly.

The major benefit of air cooled systems is that they reduce a power plant's water usage (versus a water-cooled plant which has evaporative losses). Consequently, they are commonly considered for projects located in areas without adequate water supplies. In the case of HECA, there is a plentiful supply of suitable water available. Likewise, to a very small degree, they can avoid particulate emissions from the wet cooling tower. However, a major disadvantage of air cooled systems is that they consume a lot of power because of the large fans required. In a hot climate, the ambient air temperature (i.e., 40ºC) can severely limit the cooling potential compared with wet/evaporative cooling systems which would benefit from a cooler wet bulb temperature (i.e., 20ºC) which defines the potential for a wet system. In a power plant application, this results in a loss of efficiency (decreased power output), which increases plant costs and results in greater emissions of GHGs and criteria pollutants per kilowatt-hour from the power generator.

Additionally, air is not a particularly efficient heat transfer medium. Therefore, air cooled systems require a much larger cooling plant which is mechanically more complex. A 2009 U.S. DOE study stated that air cooled systems are three to four times more expensive than a recirculating wet cooling system.

- Drift Elimination System with limited TDS level

High-efficiency drift eliminators and limits on TDS concentrations in the circulating water are the techniques that set the basis for cooling tower BACT emission limits. The efficiency of drift eliminator designs is characterized by the percentage of the circulating water flow rate that is lost to drift. The drift eliminators to be used on the proposed cooling tower will be designed such that the drift rate is less than 0.0005 percent of the circulating water.

There is no PM_{10} BACT guideline for mechanical draft cooling towers in the SJVAPCD. However, the use of high-efficiency drift-eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is a commercially proven technique to reduce PM_{10} emissions. Compared to "conventional" drift eliminators, advanced drift eliminators reduce the PM_{10} emission rate by more than 90 percent.

In addition to the use of high-efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentrations of dissolved solids in the make-up water as the circulating water evaporates; and secondarily, to the addition of anti-corrosion, anti-biocide additives.

3. Rank Control Technologies

For the control of PM from the cooling towers the following technologies in order of emission control effectiveness are:

- Air Cooled Condenser Technology
- Drift Elimination System with limited TDS level

4. Evaluate Control Options

- Air Cooled Condenser Technology

Cost effectiveness analysis

A cost effectiveness analysis was conducted for the previous configuration of the HECA Project to determine if ACC would be cost effect to control PM emissions. The study examined the power cooling tower, although the operational capacity of this cooling tower has changed, the relative cost per ton of controlled PM is expected to remain similar. Below is the previous discussion.

The Water Minimization Study conducted by Fluor engineers and documented in Appendix X of the AFC (May 2009) provides a comparison of the performance and cost impact of using an ACC versus a water cooled condenser (WCC) for the power block of the Project. The performance and cost effectiveness analyses for an ACC system were conducted on the power block for the Project because this system represented the majority of the cooling load compared to the rest of the Project. The cost-effectiveness based on the increased capital costs/capital recovery for using an ACC system for the other cooling loads proposed in the Project would be comparable to those for the power block.

The HECA Water Minimization Study considered the total installed capital cost of an ACC system compared to the proposed WCC system for the steam turbine generator power block. Using the WCC as a "Base Case," the additional installed capital cost required for an ACC is estimated at approximately $37 million dollars.

The Cost-Effectiveness of using an ACC system can be calculating by dividing the total annualized cost by the amount of particulate matter emission reduction achieved using this type of system. Total annualized cost is calculated by annualizing the capital cost (capital recovery) and including other direct annual costs (labor, maintenance, utilities) and other indirect annual costs (property taxes, insurance, administrative charges, and overhead). However, to conservatively illustrate the poor cost-effectiveness for using an ACC to control particulate matter for the power block, the following calculation includes only the capital recovery component in the total annualized cost. Assuming a 7 percent interest and 20-year life the Capital Recovery Factor (CRF) is 0.0944. This results in a total annualized cost of $3.5 million dollars per year. The total particulate matter emissions from the power block cooling tower were estimated to be 16.4 tons per year. This results in a cost-effectiveness of greater than $213,900/ton of PM controlled based solely on the capital recovery costs, using techniques from

the USEPA Cost Control Manual (USEPA, 2002). This cost would be even higher if the increased energy needs of the ACC were included (as discussed below). HECA believes that this high cost per ton of PM for using an ACC is cost prohibitive for the Project.

The "power output" of the steam turbine generator is partially dependent on the temperature of the coolant delivered to the surface condenser. The use of an ACC design will have warmer coolant temperature (ambient air) versus a water cooled design. Consequently, an ACC results in a slightly lower steam turbine generator output. Additionally, the electricity usage for running the fans for an air cooled system is higher than needed for a WCC. Compared to a WCC design, this decreased power output and increase parasitic power consumption would decrease the net electrical generation of an ACC design for the power block by approximately 8.4 MW. This increased electrical consumption/decreased output significantly would increase the annual operating costs for the air cooled system. Even conservatively valued at 8 cents per kilowatt hour, this is equivalent to an additional annual electrical cost of $5.6 million dollars per year. This cost alone is significantly higher than the annualized capital recovery cost shown above. If this cost was included with the above capital recovery component of annualized cost, it would confirm the high cost per ton of PM controlled to use ACC, and further support that an ACC system is cost prohibitive for the Project.

Due to the decreased performance of the steam turbine generator coupled with the cost-prohibitive economic analysis described above results in the ACC system being rejected as an economically feasible control technology for particulate matter emissions from the Project.

- Drift Elimination System with limited TDS level

The highest control efficiency to reduce the PM_{10} emission from the proposed cooling towers involves the instillation of drift eliminators and adoption of TDS limit for the circulating water. Development of increasingly effective de-entrainment structures has resulted in equipment vendors' claims that a cooling tower may be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate for the HECA Project. This level of reduction has been approved in other recently permitted IGCC projects.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps.

Process cooling with an ACC system was rejected as an economically feasible control technology for particulate matter emissions from the Project. Thus, a drift elimination system is selected as BACT for the proposed cooling towers. The proposed cooling tower will be designed with a high-efficiency drift elimination system to minimize potential drift and particulate emissions, achieving a maximum drift of 0.0005 percent of the circulating water. This measure, along with a limit on the circulating water TDS, is considered to be the BACT option for particulate emissions from the cooling towers.

6.4 Auxiliary Boiler BACT Analysis

The auxiliary boiler will provide steam to facilitate CTG start-up, and for other industrial purposes. The auxiliary boiler will be designed to burn pipeline-quality natural gas at the design maximum fuel flow rate of 213 MMBtu/hr (HHV). During operation, the auxiliary boiler may be kept in warm standby (steam sparged, no firing) or cold standby (no firing), and will not have emissions. The boiler will produce a maximum of about 150,000 pounds per hour of steam.

Pollutant emissions from natural gas boiler units include NO_X, PM_{10}, CO, SO_2, and VOCs. The auxiliary boiler emissions are based on 2,190 hours of operation per year. The applicant is proposing proper boiler design and operation, low-NO_X combustors with Flue Gas Recirculation (FGR), Selective Catalytic Reduction (SCR) and use of natural gas to be the BACT for the auxiliary boiler. This emission limitation is proposed to meet the SJVAPCD BACT Guidelines for greater than 20.0 MMBtu/hr natural-gas–fired boiler (base-loaded or with small load swings).

1. Identify Control Technologies

The following criteria pollutant emissions control technologies were evaluated for the proposed auxiliary boilers:

Potential Auxiliary Boiler Control Technology

For NO_X emission controls

- Low-NO_X combustor
- Low-NO_X combustor with Flue Gas Recirculation
- Selective Catalytic Reduction
- Selective Non-Catalytic Reduction

For CO emission controls

- Good Combustion Practices
- CO Oxidation Catalysts

6.4.1 Nitrogen Oxides BACT Analysis for the Auxiliary Boiler

2. Evaluate Technical Feasibilities

- Low-NO_X Combustors

  Low-NO_X combustors reduce thermal NO_X formation by regulating the distribution and mixing of fuel and air to control the stoichiometry and temperature of combustion. Historically, low-NO_X combustors have been selected as BACT for natural-gas–fired auxiliary boilers. Therefore, low-NO_X combustor technology is technically feasible for the proposed auxiliary boiler.

- Low-NO_X Combustors with Flue Gas Recirculation

  FGR reduces boiler NO_X emissions by recirculating a portion of the flue gas into the main combustion chamber. The increase in gas flow within the combustion chamber reduces the peak combustion temperature and oxygen in the combustion air/flue gas mixture, thereby reducing the formation of thermal NO_X. The application of FGR is typically in combination with low-NO_X combustor technology and has been selected as BACT for some auxiliary boiler processes. Therefore, FGR is considered technically feasible for the proposed auxiliary boiler.

- Selective Catalytic Reduction

  SCR is a technology that achieves post-combustion reduction of NO_X from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of NO_X to molecular nitrogen. SCR technology has been most commonly applied to pulverized coal–generating units and to natural gas–fired combustion turbines.

- Selective Non-Catalytic Reduction

  Selective non-catalytic reduction is a post-combustion NO_X control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with NO_X to form elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO_X emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas, which must occur within a narrow flue gas temperature zone (typically from 1,700°F to 2,000°F).

  The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_X. Below the lower end of the temperature range, the reagent will not react with the NO_X, resulting in very high ammonia slip concentrations (ammonia discharge from the stack).

  Although there are expected to be technical difficulties with SNCR, due to the lack of flue gas locations within the process with the optimal requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions, the RBLC shows SNCR applied in only two boiler units greater than 100 MMBtu/hr. The control cited in both of these examples is 60 percent.

3. Rank Control Technologies

The RBLC examples for low-NO_X combustors combined with either FGR or SCR give efficiencies of up to 95 percent with FGR and efficiencies of up to 97 percent with SCR. Both of these technologies have reported control efficiencies that are significantly greater than that for SNCR. Low-NO_X combustors and SCR have recently been selected as BACT for other projects, and report slightly greater control than low-NO_X combustors with FGR. The expected emission rate for the HECA auxiliary boiler operating with low-NO_X combustors and FGR is 9 ppm NO_X

at 3 percent oxygen, while the expected emission rate with low-NO_X combustors and SCR is 5 ppm NO_X at 3 percent oxygen.

4. Select Control Technology

Low-NO_X combustor technology and flue gas recirculation have historically been selected as BACT for natural-gas–fired auxiliary boilers. These technologies are commonly used in combination to reduce NO_X emissions in other recently permitted IGCC projects. However, the HECA auxiliary boiler is expected to have more NO_X control by using SCR instead of FGR, as mentioned above. Therefore, the proposed auxiliary boiler will be designed with a Low-NO_X combustor technology and SCR, achieving a maximum NO_X emission concentration of 5 ppm NO_X at 3 percent oxygen on natural gas fuel.

6.4.2 Carbon Monoxide BACT Analysis for the Auxiliary Boiler

An inadequate degree of fuel mixing, lack of available oxygen, or low temperatures in the combustion zone are common causes of incomplete combustion that results in CO emissions. Fuel quality and good combustion practices can limit CO emissions. Good combustion practice has commonly been determined as BACT for natural gas–fired auxiliary boilers. Post-combustion control technologies using catalytic reduction have also been employed in some processes to reduce CO and VOC emissions.

2. Evaluate Technical Feasibilities

Good Combustion Practices

GCPs include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. Good combustion practice has historically been determined as BACT for CO and VOC emissions from auxiliary boilers, and is a technically feasible control strategy for the proposed auxiliary boiler.

Oxidation Catalyst

Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize CO and VOC into CO_2 or H_2O. The technology has most commonly been applied to natural gas–fired combustion turbines. No examples were identified where oxidation catalyst technology has been applied to an auxiliary boiler. Because of the low potential CO and VOC emission without an oxidation catalyst and the limited use of the proposed auxiliary boiler, the use of catalytic oxidation technology is determined to be infeasible.

3. Rank Control Technologies

Good combustion practice is the only feasible control strategy identified, and has historically been selected as BACT for CO emissions from the auxiliary boiler.

4. Select Control Technology

The use of good combustion practices has been selected as BACT for potential CO emission from the proposed auxiliary boiler. Boiler vendor information indicates that a CO worst-case hourly emission for the proposed auxiliary boiler is 50 ppmvd at 3 percent oxygen.

6.4.3 Particulate Emissions, Sulfur Oxides, Volatile Organic Compounds BACT Analysis for the Auxiliary Boiler

For these pollutants, the commercially available control measures that are identified in the most stringent BACT determinations are use of low-sulfur, PUC natural gas, and GCP. Based on SJVAPCD BACT Guidelines for > 20.0 MMBtu/hr Natural Gas–Fired Boiler (base-loaded or with small load swings), add-on controls were not implemented to achieve BACT limits for these pollutants.

Boiler vendor information indicates that the worst-case hourly emissions for this unit with these technologies would be 0.00285 lb SO_2/MMBtu; 0.004 lb VOC/MMBtu; and 0.005 lb PM_{10}/ MMBtu. These rates, or corresponding lb/hour emission rates, are proposed as BACT limits for the auxiliary boiler emission unit.

6.5 Diesel Engines BACT Analysis

The Project will include two 2,922 HP standby diesel generators and one 556 HP, standby firewater pump. HECA proposed to apply the SJVAPCD BACT Guidelines for Emergency Diesel I.C. Engine = or > 400 hp as the BACT for the standby diesel generator engines, and SJVAPCD BACT Guidelines for Emergency Diesel I.C. Engine Driving a Fire Pump as the BACT for the standby firewater pump engine. The BACT emission limits will be achieved by the following control effort.

- Low Sulfur Fuel Selection

  The diesel engines will exclusively combust ultra-low sulfur diesel fuel. SO_2 emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur.

- Clean Combustion Process Selection

  The engines will meet USEPA interim Tier 4 emissions standards.

  Standby diesel generator engine: 0.3 g/bhp-hr NMHC; 0.5 g/bhp-hr NO_X; 2.6 g/bhp-hr CO; 0.07 g/bhp-hr PM

  Standby firewater pump engine: 0.14 g/bhp-hr NMHC; 1.5 g/bhp-hr NO_X; 2.6 g/bhp-hr CO; 0.015 g/bhp-hr PM

- Restricted Operating Hours

  The standby diesel generators will operate less than 50 hours per year per engine for non-emergency purposes such as: routine testing, maintenance, and inspection purposes. The fire pump will operate than less than 100 hours per year per engine for non-emergency purposes.

6.5.1 BACT Analysis for the Standby Diesel Generators

The achieved-in-practice or contained in the SIP BACT guideline for NO_X is certified emissions of 6.9 g/bhp-hr or less. The proposed control of using engines that meet USEPA interim Tier 4 emissions standards for 2011 and newer model equipment will meet this BACT limit with 0.5 g/bhp-hr NO_X. Although it is technically feasible to install add-on NO_X control, this option is cost prohibitive due to the emergency nature of the engine operations.

The achieved-in-practice or contained in the SIP BACT guideline for CO is 2.0 g/bhp-hr. The vendor emission factor for the diesel engines guaranteed 0.29 g/bhp-hr of CO emission. This emission limit is substantially below the required BACT limit. Although it is feasible to install a CO oxidation catalyst to further reduce CO emissions from the engines, the cost for oxidation catalyst for CO control will be prohibitive, given the low number of routine operating hours per year of the engines.

The achieved-in-practice or contained in the SIP BACT guideline for PM_{10} is 0.1 gram/bhp-hr (if TBACT is triggered) or 0.4 g/bhp-hr (if TBACT is not triggered). The proposed control of using engines that meet USEPA interim Tier 4 emissions standards will meet this BACT limit with 0.07 g/bhp-hr PM.

The achieved-in-practice or contained in the SIP BACT guideline for sulfur oxides is low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-Sulfur Diesel fuel (15 ppmw sulfur or less). The standby diesel generator engines will exclusively combust ultra-low sulfur diesel fuel. SO_2 emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur.

There is no numerical emission limit achieved in practice or contained in the SIP BACT guideline for VOC. The proposed control of using engines that meet USEPA interim Tier 4 emissions standards for 2011 and newer model equipment proposed a BACT limit with 0.3 g/bhp-hr VOC for this unit.

6.5.2 BACT Analysis for the Firewater Pump Diesel Engine

The achieved-in-practice or contained in the SIP BACT guideline for NO_X is certified emissions of 6.9 g/bhp-hr or less. The proposed control of using engines that meet USEPA interim Tier 4 emissions standards will meet this BACT limit with 1.5 g/bhp-hr NO_X. Although it is technically feasible to install add-on NO_X control, this option is cost prohibitive due to the emergency nature of the fire/water pump engine operations.

There is no numerical emission limit achieved in practice or contained in the SIP BACT guideline for CO. The proposed control of using engines that meet USEPA interim Tier 4

emissions standards proposed a BACT limit with 2.6 g/bhp-hr CO for this unit. Although it is feasible to install a CO oxidation catalyst to further reduce CO emissions from the engines, the cost for an oxidation catalyst for CO control will be prohibitive, given the low number of routine operating hours per year of the fire water pump.

The achieved-in-practice or contained in the SIP BACT guideline for PM_{10} is 0.1 grams/bhp-hr (if TBACT is triggered) or 0.4 grams/bhp-hr (if TBACT is not triggered). The proposed control of using engines that meet USEPA interim Tier 4 emissions standards will meet this BACT limit with 0.015 g/bhp-hr PM.

The achieved-in-practice or contained in the SIP BACT guideline for sulfur oxides is low-sulfur diesel fuel (500 ppmw sulfur or less) or ultra-low sulfur diesel fuel (15 ppmw sulfur or less). The firewater-pump diesel engine will exclusively combust ultra-low sulfur diesel fuel. SO_2 emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur.

No numerical emission limit is achieved in practice or contained in the SIP BACT guideline for VOC. The proposed control of using engines that meet USEPA interim Tier 4 emissions standards for 2011 and newer model equipment proposed a BACT limit with 0.14 g/bhp-hr VOC for this unit.

6.6 Gasification Flare BACT Analysis

The gasification block will be provided with a relief system and associated gasification flare to safely dispose of gasifier streams during start-up, shut-down, and unplanned upsets or emergency events, syngas during AGR start-up, hydrogen-rich gas during short-term emergency combustion turbine outages, or other various streams within the Project during other unplanned upsets or equipment failures. Syngas sent to the flare during normal planned flaring events is filtered, water-scrubbed and further treated in the AGR Unit to remove regulated contaminants prior to flaring.

Two flare-control technologies were evaluated for the proposed facility: an elevated flare, and an enclosed ground flare. Elevated flare technology uses a stack to vent combustible process gases to a combustor located at the top, resulting in an open flame at the stack discharge. Elevated flares provide for greater dispersion of heat and combustion products than ground flares. Elevated flares are the most common technology used by refinery, steel, and chemical industries, and are used by operational and recently permitted IGCC projects.

Compared to an elevated flare, an enclosed ground flare offers better CO destruction. However, enclosed ground flares pose potentially decreased dispersion of combustion gases and increased reliability concerns and have never been installed on any IGCC plants and so are considered unproven technology in this application with an associated risk. Elevated flares are used extensively with IGCC applications and therefore, the gasification block will be designed with an elevated flare to safely dispose of gasifier start-up gases, hydrogen-rich fuel during AGR start-up, hydrogen-rich gas during short-term emergency combustion turbine outages, or other various streams within the Project during other unplanned upsets or equipment failures.

The flare, when in operation, will emit criteria pollutants that are products of combustion. However, the chemical compositions of the predominant gaseous fuels that would be flared; i.e., syngas and natural gas, result in low emissions of PM_{10}, SO_2, and VOC. For the syngas case, there is very little unoxidized carbon in the fuel, which limits the formation of particulate matter during combustion even below the rate for natural gas. Formation of SO_2 is limited by not intentionally flaring untreated syngas and the inherently low sulfur content of treated syngas and pipeline natural gas.

1. Identify Control Technologies

The following control technologies were evaluated for the proposed gasification flare:

- Clean pilot fuel (Natural gas) and Good Combustion Practices
- Low-NO_X Combustor
- Add-On Controls
- Limited Operation

2. Evaluate Technical Feasibilities

- Clean pilot fuel (Natural Gas) and Good Combustion Practices

  A certain level of flame temperature control can be exercised for the gasification flare by implementing fuel/air ratio control. Flare BACT options that have been achieved in practice in California (e.g., CAPCOA BACT Clearinghouse) indicate a natural gas pilot and "proper burner management and monitoring" are used to control the emissions of CO, VOCs and NO_X.

- Low-NO_X Combustor

  Low-NO_X combustor and ultralow-NO_X combustor technology alter air-to-fuel ratio in the combustion zone by staging the introduction of the air to promote a "lean-premixed" flame. This results in lower combustion temperatures and reduced NO_X formation. Such designs are not available for elevated flares that do not have a confined combustion zone, which would allow staged introduction of fuel and air streams. Therefore, this control technology is not feasible for the proposed gasification flare.

- Add-On Controls

  The gasification block flare is not a candidate for add-on abatement systems. It is generally recognized in the chemical process industries that adoption of add-on control can impede the ability of a flare to respond to unexpected upset conditions. Therefore, this control technology is not feasible for the proposed gasification flare.

- Limited Operations

  The gasification flare planned operation will be limited to gasifier start-ups and shut-downs, which occurs at most twice a year.

For plant safety, the flare must provide a "fail-safe" that is available regardless of the functioning of pollution control devices.

3. Rank Control Technologies

The use of natural gas as pilot fuel, good combustion practices and limited operation were identified as the only technically feasible criteria pollutant emissions control technologies applicable to the proposed gasification flare.

4. Evaluate Control Options

As determined in the last section, the use of natural gas as pilot fuel, good combustion practices and limited operation are the only feasible control strategy identified. Based on review of SJVAPCD BACT guideline, there is no BACT determination source category for flare that supports the gasification process.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, use of natural gas as pilot fuel, good combustion practices and limited operation are selected as BACT for the proposed gasification flare. The measure, along with natural gas pilot and processes flare gas for non-emergency operation are considered to be the best available control option for criteria pollutant emissions from the gasification flare. The proposed criteria pollutant emissions for the gasification flare are summarized in Table 6-8.

Table 6-8
Gasification Flare Total Criteria Pollutant Emissions

Pollutant	Emissions		
	Pilot (ton/yr)	Start-Up/ Shut-Down (ton/yr)	Total (ton/yr)
NO_X	0.263	2.91	3.17
CO	0.175	18.28	18.46
VOC	0.003	0.01	0.01
SO_2	0.004	0.02	0.02
PM_{10}	0.007	0.03	0.03

Notes:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter 10 microns in diameter or less
SO_2 = sulfur dioxide
VOC = volatile organic compound

6.7 Sulfur Recovery System BACT Analysis

The sulfur recovery system is designed to process acid gas streams from the AGR system and IGCC process into an elemental sulfur product. Sulfur is removed from the processing facility through a sulfur complex which consists of a Claus unit (thermal stage) plus catalytic converters otherwise known as the SRU. The SRU is a totally enclosed process with no discharges. The tail gas stream from the SRU is composed mostly of carbon dioxide, water vapor, and sulfur vapor with trace amounts of H_2S and SO_2. The tail gas is routed to the Tail Gas Treating Unit (TGTU) where the tail gas is catalytically hydrogenated, compressed, and completely recycled to the Shift Unit.

The proposed sulfur process facility consists of one 100 percent SRU, and one TGTU. HECA proposed the integral use of two elevated flares, a caustic scrubber, and a thermal oxidizer as control devices to provide for the safe and efficient destruction of combustible gas streams. These control devices are primarily used intermittently during short-term periods of start-up, shut-down, and malfunction operations.

1. Identify Control Technologies

The following control technologies were evaluated for the proposed Sulfur Recovery System:

- Thermal Oxidizer
- Flare
- Caustic Scrubber
- Limited Operation

2. Evaluate Control Technologies

- Thermal Oxidizer

  In the thermal oxidizer, the TGTU tail gas and other oxidizing streams are subjected to a high temperature and a sufficient residence time to cause an essentially complete destruction of reduced sulfur compounds such as H_2S. The thermal oxidizer uses natural gas to reach the necessary operating temperature for optimal thermal destruction. The thermal oxidizer also controls emissions from various systems during operations, including the sulfur pit vent. A continuous natural gas pilot will be in service on both controls. The flare and thermal oxidizer are the only control technologies identified that are capable of controlling the variable potential gas streams associated with the sulfur recovery process and the start-up, shut-down, and malfunction of the integrated IGCC systems.

  Good thermal oxidizer design includes optimization of parameters that maintain efficiency, such as temperature, residence time, and the mixing of gas streams in the combustion zone. The proposed thermal oxidizer will use natural gas for preheating and to facilitate the combustion of process gases in the thermal oxidizer. Implementation of these elements into the design and operation of the thermal oxidizer, in combination with the use of a natural-gas pilot flame, will support a thermal oxidizer control technology that minimizes incomplete combustion, which directly correlates to potential criteria pollutant emissions.

- Flare

  Emissions from the IGCC gas cleanup process cannot be directed to certain control systems and/or the combustion turbines during start-up and shut-down operations, or during operational malfunctions. Directly venting these emissions could result in very high concentrations of SO_2, CO, VOCs, NO_X, and/or H_2SO_4 being released. In this case, two elevated flares are selected to accommodate the variability inherent in these operations: Sulfur Recovery Unit Flare, and Rectisol® Flare.

  The SRU Flare will be used to safely dispose of gas streams containing sulfur during start-up and shut-down, and gas streams containing sulfur during unplanned upsets or emergency events. Acid gas derived from the AGR, gasification unit, and Sour Water Stripper overhead is normally routed to the SRU for recovery as elemental sulfur. During cold plant start-up of the gasifiers, AGR, and Shift units, these acid-gas streams will be diverted to the SRU Flare Header for a short time. To reduce the emissions of sulfur compounds to the environment during SRU or TGTU shutdown, the acid gas is routed to the Emergency Caustic Scrubber, where the sulfur compounds are absorbed with caustic solution. After scrubbing, the gas is then routed to the elevated SRU Flare Stack. It is expected that a maximum of 40 hours per year of flaring for this purpose would be required by this flare.

  The Rectisol® flare may be used for off-specification carbon dioxide during gasifier start-up or shut-down events. It is expected that a maximum of 40 hours per year of flaring for this purpose would be required by this flare.

  Enclosed ground flares have the potential to minimize flame appearance and provide a setting for monitoring post-combustion gas streams. However, they have not been proven for the proposed facility because of reliability concerns.

  Elevated flares are used extensively with IGCC applications and therefore, are considered proven technology. The SRU will be designed with an elevated flare.

- Caustic Scrubber

  During cold plant start-up of the gasification block, acid-gas streams will be diverted to a caustic scrubber prior to being directed to the elevated flare for a short time. The caustic scrubber removes H_2S from the acid gas stream with an anticipated scrubbing efficiency of at least 99.6 percent sulfur removal.

3. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As discussed, the use of flares, thermal oxidizer, and caustic scrubber are the proposed technologies designed to control criteria pollutant emissions from the sulfur recovery system, in addition to an efficient IGCC process design. These technologies complement one another, and may operate in combination with each other. In addition, limited planned operation of each will control emissions.

Including the proposed control system to provide for the safe and efficient destruction of combustible sulfur-rich acid-gas streams, the emissions from the sulfur recovery system are categorized into three emission sources of tail gas thermal oxidizer, SRU flare and Rectisol® flare (elevated flares with natural gas assist). Each emission source has its own emission control measure to reduce its criteria pollutant emissions. The proposed criteria pollutant emissions for the sulfur recovery system are summarized in Table 6-9. HECA has selected all of the control technologies that were evaluated for the Sulfur Recovery System, and proposes these as BACT for the Project.

Table 6-9
Sulfur Recovery System Emissions

Pollutant	Thermal Oxidizer Emissions (lb/MMBtu, HHV)	SRU Flare Emissions			Rectisol® Flare Emissions		
		Pilot (ton/yr)	Start-Up/ Shut-Down (ton/yr)	Total (ton/yr)	Pilot (ton/yr)	Start-Up/ Shut-Down (ton/yr)	Total (ton/yr)
NO_X	0.24	0.158	0.09	0.24	0.158	1.03	1.19
CO	0.2	0.105	0.06	0.16	0.105	0.69	0.79
VOC	0.006	0.002	0.00	0.00	0.002	0.01	0.01
SO_2	See Below	0.003	0.37	0.37	0.003	0.30	0.30
PM_{10}	0.008	0.004	0.00	0.01	0.004	0.03	0.03

Assume an allowance of 2 lb/hr SO_2 emission to account for sulfur in the various vent streams, plus fuel.

Notes:

CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter 10 microns in diameter or less
SO_2 = sulfur dioxide
VOC = volatile organic compound

6.8 CO_2 Vent BACT Analysis

The Project will produce electricity while substantially reducing GHG emissions by capturing CO_2. At least 90 percent of the carbon in the raw syngas will be captured in a high-purity carbon dioxide stream during steady-state operation. The high-purity CO_2 will be compressed and transported by pipeline to the EHOF for injection into deep underground hydrocarbon reservoirs for CO_2 EOR.

A CO_2 vent stack will allow for infrequent venting of produced CO_2 from the AGR and TGTU when the CO_2 injection system is unavailable, unable to export, or other upset condition. The CO_2 vent will enable HECA to operate, rather than be disabled, by brief periods of gasifier shutdown and subsequent gasifier restart. The CO_2 vent exhaust stream will be nearly all CO_2, with small amounts of CO, VOC, and H_2S.

Due to the infrequent nature of the venting event, the option of using add-on control technology is cost prohibitive for this emission point. In order to reduce the impact of these infrequent

venting events, the BACT selected for this source include good operating practices, good engineering practice stack height, limited venting duration, and vent gas concentration limits.

HECA proposes to limit venting to a maximum of 504 hours at maximum venting rate for this unit. The pollutant concentrations in the vent gas are limited to 1,000 ppm for CO, 40 ppm for VOCs, and 10 ppm for H_2S to reduce the overall impact of the venting event.

Good Engineering Practice Stack Height

The USEPA provides specific guidance for determining the Good Engineering Practice (GEP) stack height and for determining whether building downwash will occur in the *Guidance for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations*). GEP is defined as "the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles."

The GEP definition is based on the observed phenomenon of atmospheric flow in the immediate vicinity of a structure. It identifies the minimum stack height at which significant adverse aerodynamics (downwash) are avoided. The USEPA GEP stack height regulations specify that the GEP stack height is calculated in the following manner:

$$H_{GEP} = H_B + 1.5L$$

where:

H_B = the height of adjacent or nearby structures; and

L = the lesser dimension (height or projected width) of the adjacent or nearby structures.

The regulations also specify that the creditable stack height for modeling purposes is either the GEP stack height as calculated, or a *de minimis* height of 65 meters.

A 260-foot stack height was chosen to satisfy HECA's inherently safe design practices to minimize ground-level CO_2 concentrations in the event of a CO_2 vent under very low wind speeds.

6.9 Material Handling System BACT Analysis

Particulate matter emissions are associated with the material handling of with the feedstock (petcoke and coal), and dry product (urea and gasification solids). The conveyance and preparation processes related to the feedstock and products have a potential to emit particulate matter. The following is the BACT analysis for the proposed material handling system at HECA.

6.9.1 Particulate Matter BACT Analysis for the Material Handling System

Because the feedstock preparation processes will be within an enclosed conveyor system, a forced air dust collection system is the most appropriate and common control technology for particulate matter emission control from the emission points. The material handling system will consist of the following activities, all with associated baghouses:

- Truck/Train feedstock unloading
- Petcoke/coal crushing building and transfer towers
- Urea transfer towers
- Urea unloading buildings
- Gasification solids transfer tower and load-out

HECA selected dust collection systems consisting of baghouses as BACT to control particulate emissions from the aforementioned emission points. The baghouses associated with the material handling at HECA will have a maximum dust collector PM emission rate based on expected supplier guarantee of 0.001 grain/scf outlet dust loading.

A dust collection system using baghouses has been proposed as BACT in other operating and recently permitted IGCC projects. The proposed emission limitation represents a removal efficiency that is comparable or lower with the emissions achieved in practice at currently operating IGCC units, and the lowest recently permitted IGCC units.

6.10 Manufacturing Complex BACT Analysis

The BACT analysis for the Manufacturing Complex is broken down by emission units. Nitrogen-based product production at HECA consists of: an ammonia synthesis unit, where the only emission source is an ammonia plant start-up heater (combustion emissions); a urea unit (scrubber emissions); a urea pastillation unit (particulate matter emissions); and a Urea Ammonium Nitrate (UAN) Unit, consisting of a nitric acid unit and an ammonium nitrate unit as emission sources. BACT for the material handling processes for the Manufacturing Complex are addressed in Section 6.9. The RBLC was examined for similar sources. Most of the facilities listed in the RBLC are different from the HECA Manufacturing Complex; however, there are many similar components. Thus many of the proposed BACT levels are not compared to those from existing facilities unless similar source units had process operations (such as unit inputs and outputs) that were comparable to HECA.

6.10.1 Ammonia Synthesis Unit

The high-purity hydrogen stream, from the Pressure Swing Adsorption (PSA) Unit, and nitrogen, from the ASU, are combined in an exothermic ammonia synthesis reaction that takes place at high temperature and high pressure across an iron-based catalyst. There is a large degree of heat integration within the Ammonia Synthesis Unit, and the substantial heat of reaction is recovered and used to generate steam. Cold liquid ammonia is stored in a tank at atmospheric pressure.

There are no normal operating emissions from the ammonia synthesis unit. However, a start-up heater (natural gas-fired) is used to heat the catalyst during a cold start of the unit. A 55 MMBtu/hr natural gas–fired start-up heater is provided in the ammonia synthesis unit to raise the catalyst-bed temperatures during initial plant commissioning or during start-up after a long period of plant shutdown.

The annual heat input for this heater is not expected to exceed 7,700 MMBtu (HHV), which is equivalent to approximately 140 hours of operation at full capacity.

The heater will use a low-NO_X burner to control emissions to 9 ppm. The heater will only combust natural gas, therefore the potential for SO_2, VOC, and PM emissions is minimized. Good combustion practices will optimize the performance of the heater, thereby minimizing the emissions of CO. The proposed BACT emission rates for the ammonia synthesis start-up heater are presented in Table 6-10. Therefore, BACT for the heater was determined to be a low-NO_X burner, GCP, natural gas fuel, and restricted operating hours.

Table 6-10
Ammonia Synthesis Startup Heater Emissions

Pollutant	Emission Limit
NO_X	0.011 lb/MMBtu, HHV – 9 ppmvd (3% O_2)
CO	0.037 lb/MMBtu, HHV – 50 ppmvd (3% O_2)
PM_{10}	0.005 lb/MMBtu, HHV
SO_2	0.002 lb/MMBtu, HHV (12.65 ppm)
VOC	0.004 lb/MMBtu, HHV

Notes:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter 10 microns in diameter or less
SO_2 = sulfur dioxide
VOC = volatile organic compound

6.10.2 Urea Unit – High and Low Pressure Absorbers

The purified and compressed carbon dioxide and the liquid ammonia are reacted in the Urea Unit to create a concentrated urea solution, which is pumped to the Urea Pastillation Unit. Lower-concentration urea solution is produced as a feedstock to the urea ammonia nitrate (UAN) Solution Plant. Vacuum evaporator/separator systems are used to produce the required urea solutions.

The off-gases from the urea synthesis process, consisting of inerts present in the CO_2 feed, process air and unreacted ammonia are cleaned before being vented in the high-pressure (HP) scrubber, which operates at an elevated pressure. The off-gases are scrubbed first with process water, and second with clean cold water. In this way, nearly all of the ammonia is scrubbed from the gas.

Low pressure off-gases are cleaned in the low-pressure (LP) scrubber, which operates at close to atmospheric pressure. Here, the off-gas is scrubbed with clean cold water to reduce the ammonia content in the vent.

The only emissions associated with the HP and LP Absorbers are ammonia, which are reduced by the wet scrubbers. HECA proposes BACT for the HP and LP Absorbers to be wet scrubbers.

6.10.3 Urea Unit- Pastillation

The pastillation process is used to convert the urea melt into high-quality pastilles. This process is enclosed with a hood, passed through a baghouse then vented. Limited ammonia and urea dust, which is classified as PM_{10}, are emitted from this source.

The only BACT level grain loading provided was 0.0960 gr/dscf. The RBLC shows no listings for ammonia emissions or control.

The vent from the urea pastillation building is treated with a baghouse filter in order to reduce the particulate loading in the atmospheric vent. The HECA granulation process PM/PM_{10} emissions are expected to have a grain loading of 0.001 gr/dscf with use of a baghouse, and is therefore considered BACT.

HECA proposes BACT for the Urea Pastillation Unit to be a baghouse with a grain loading of 0.001 gr/dscf.

6.10.4 Nitric Acid Unit

Nitric acid production is a three-step process consisting of ammonia oxidation, nitric oxide (NO) oxidation and absorption. Tail gas from the absorber column will be cleaned before being discharged by catalytic decomposition and reduction of both nitrous oxide (N_2O) and NO_X.

1. Identify Control Technologies

The following NO_X control technologies were evaluated for the proposed Nitric Acid Unit:

- Extended Absorption with Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

2. Evaluate Technical Feasibilities

- Extended Absorption with Selective Non-Catalytic Reduction

  Extended absorption reduces NO_X emissions by increasing absorption efficiency and is achieved by either installing a single large tower, extending the height of an existing absorption tower, or by adding a second tower in series with the existing tower.

Selective non-catalytic reduction is a NO_X control technology in which a reagent (ammonia or urea) is injected into the flue gases to react chemically with NO_X to form elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO_X emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas, which must occur within a narrow flue gas temperature zone (typically from 1,700°F to 2,000°F). The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_X. Below the lower end of the temperature range, the reagent will not react with the NO_X, resulting in very high ammonia slip concentrations (ammonia discharge from the stack).

Although there are expected to be technical difficulties with Extended Absorption with SNCR, due to the lack of flue gas locations within the process with the optimal requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions and the need for larger or additional absorption towers, the RBLC shows Extended Absorption with SNCR was applied at one nitric acid plant. The control cited was 1.6 lb/ton of nitric acid produced.

- Selective Catalytic Reduction

  SCR is a technology that achieves reduction of NO_X from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of NO_X to molecular nitrogen.

  A RBLC review identified that SCR technology has been applied to a number of nitric acid plants lowering NO_X emissions as low as 0.524 lb/ton of nitric acid produced.

3. Rank Control Technologies

The RBLC review provided examples of NO_X control with SCR and Extended Absorption with SNCR, neither is identified as providing more control of NO_X.

4. Evaluate Control Options

The next step in a BACT analysis is to evaluate the feasible control technology. Based on the evaluation in the previous step, the technology with the maximum control is SCR.

The N_2O emissions are treated in a tertiary reduction system, based on its location at the end of the tail gas heat recovery system. Primary and secondary reduction occurs in the nitric acid unit equipment without any catalysis simply by the high process temperature. In the tertiary reduction, a reducing catalyst that uses high temperature rather than a reducing agent, converts 95 percent of the remaining N_2O emission to molecular nitrogen (N_2) and nitric oxide (NO). The NO_X emissions (including the NO formed in the N_2O converter) are then reduced in one or more selective catalytic reduction (SCR) units, with injected ammonia as a reducing agent, as is typical for NO_X control in flue gas systems. Total NO_X emissions from this unit will not exceed 0.2 lb/ton of dry nitric acid or 15 ppmv NO_X.

This is far below the NSPS of 3 lb/ton, the proposed NSPS of 0.50 lb/ton, and also well below other limits cited in the RBLC, which range from 0.52 to 3.0 lb/ton, using NSCR or SCR. The levels of control vary for each of these control types; neither is identified as providing more control of NO_X. Injection of hydrogen peroxide is also listed as BACT for one source, with a NO_X limit of 0.6 lb/ton HNO_3. Because the expected NO_X emission level for the HECA nitric acid unit is well below these values, it is considered that BACT is the application of SCR for control of NO_X emissions from the nitric acid unit.

Only one source in the RBLC noted a limit for ammonia emissions due to ammonia slip. This source had a BACT limit of 10 ppmv. The HECA nitric acid plant will have an emission limit of 5 ppm for ammonia due to slip from the SCR unit and proposes this as the BACT level.

5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. For the nitric acid unit at HECA, SCR to control NO_X emission limits is considered BACT. HECA proposes the SCR to control NO_X on the nitric acid unit to 0.2 lb/ton of dry nitric acid and an emission limit of 5 ppm for ammonia due to slip from the SCR unit.

6.10.5 Ammonium Nitrate Unit

The ammonia and nitric acid are the feedstocks to the ammonium nitrate unit, which makes the ammonium nitrate solution. The ammonium nitrate unit vent stream contains water vapor and residual ammonium nitrate solution mist that is not removed by the demisting system. If this vent stream with mist is emitted directly, the mist droplets would evaporate and result in PM emissions. These particulate emissions are substantially reduced by routing the vent stream to a water scrubbing system before discharge. This vent scrubber condenses the vapor into condensate which then absorbs the previously entrained mist droplets. The condensate stream is either recycled to the neutralizer or mixed with cooling tower blowdown for treatment and disposal. For this plant, a near total condensing vent scrubbing system will be used and the scrubber vent particulate emissions will be less than 0.2 lb/hr. Review of the RBLC for ammonium nitrate plants show wet scrubber use in all systems.

HECA proposes BACT for the ammonium nitrate unit to be a wet scrubber with PM/PM_{10} emissions limited to 0.2 lb/hr.

6.11 Fugitive Emissions BACT Analysis

Fugitive emissions of VOC, CO, ammonia, H_2S, and trace HAPs and GHGs may occur in some areas of the facility due to leaking process equipment. Fugitive emissions are associated with the Gasification Block and the Manufacturing Complex. A leak detection and repair (LDAR) program will be implemented in select process areas to maximize emission reductions. LDAR is the primary established method for controlling fugitive emissions from various pieces of equipment, such as valves and seals, and is considered BACT. As determined by SJVAPCD, LDAR will be employed at a minimum to valves and connectors at HECA where VOC > 100 ppmv above background, and to pumps and compressor seals at HECA where VOC >

500 ppmv above background. HECA intends to apply LDAR to additional process areas beyond the SJVAPCD recommendation.

HECA proposes LDAR on select process areas as BACT to control fugitive emissions.

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Appendix C

Greenhouse Gas BACT Analysis

GREENHOUSE GAS (GHG) BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

For the

HYDROGEN ENERGY CALIFORNIA (HECA) PROJECT

Prepared by:

Hydrogen Energy California LLC

With support from:

URS

May 2012

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Figure 1 HECA CO_2e Emissions and Product Summary

Acronyms

AGR	acid gas recovery
BACT	Best Available Control Technology
Btu	British thermal unit
CCS	carbon capture and sequestration
CEC	California Energy Commission
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
COS	carbonyl sulfide
CTG	combustion turbine generator
DOE	U.S. Department of Energy
EOR	enhanced oil recovery
GAC®	granular-activated carbon
GHG	greenhouse gas
GWP	global warming potential
H_2	hydrogen
H_2S	hydrogen sulfide
HECA	Hydrogen Energy California LLC
HNO_3	nitric acid
hp	horsepower
HRSG	heat recovery steam generator
IGCC	Integrated Gasification Combined-Cycle
lb/MWh	pounds per megawatt hour
LDAR	leak detection and repair
MHI	Mitsubishi Heavy Industries
MMBtu/hr	million British thermal units per hour
MW	megawatts
N_2	nitrogen
N_2O	nitrous oxide
NSCR	non-selective catalytic reduction
NO_X	nitrogen oxides
O_2	oxygen
OEHI	Occidental of Elk Hills, Inc.
petcoke	petroleum coke
PM_{10}	particulate matter less than or equal to 10 microns in diameter
Project	Hydrogen Energy California Project
PSA	Pressure Swing Adsorption
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
RBLC	Reasonably Available Control Technology/Best Available Control Technology/Lowest Achievable Emission Rate Clearinghouse
SB	Senate Bill
SF_6	sulfur hexafluoride
SGS	sour gas recovery

ACRONYMS AND ABBREVIATIONS

SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_X	sulfur oxides
STG	steam turbine generator
SRU	sulfur recovery unit
syngas	synthesis gas
UAN	urea ammonium nitrate
USEPA	U.S. Environmental Protection Agency
VOC	volatile organic compound

1. INTRODUCTION

This document presents the Greenhouse Gas (GHG) Best Available Control Technology (BACT) analysis for the Integrated Gasification Combined Cycle (IGCC) polygeneration project proposed by Hydrogen Energy California LLC (HECA). Throughout the document, the proposed action is referred to as HECA or the Project.

In September 2011, SCS Energy California LLC acquired 100 percent ownership of HECA. HECA has modified the Project design to ensure economic viability and better serve market needs, while continuing to adhere to the strictest environmental standards. HECA respectfully submits this GHG BACT analysis for the modified Project design. This GHG BACT analysis supersedes the March 2011 analysis, and incorporates responses to comments provided by the U.S. Environmental Protection Agency (USEPA) in June 2011.

On December 16, 2010, the San Joaquin Valley Air Pollution Control District (SJVAPCD) issued the Final Determination of Compliance for the previous Project design, which is equivalent to the Authority to Construct permit for projects reviewed under the California Energy Commission Licensing process. HECA will submit a new SJVAPCD Application to Construct reflecting the modified Project design. It is expected that the new SJVAPCD permit and conditions will be similar to those previously determined.

The Project will gasify a fuel blend of 75 percent coal and 25 percent petroleum coke (petcoke) to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel and used to generate a nominal 300 megawatts (MW) of low-carbon baseload electricity in a Combined Cycle Power Block; low-carbon nitrogen-based products in an integrated Manufacturing Complex; and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR). CO_2 from HECA will be transported by pipeline for use in EOR in the adjacent Elk Hills Oil Field (EHOF), which is owned and operated by Occidental of Elk Hills, Inc. (OEHI). The EOR process results in sequestration (storage) of the CO_2.

The Combined Cycle Power Block will generate approximately 405 MW of gross power, and will provide approximately 300 MW output of low-carbon baseload electricity to the grid. The remaining power will be used on-site to meet the facility's internal loads, and routed to the Manufacturing Complex for nitrogen-based product manufacturing. The Power Block will consist of:

- one Mitsubishi Heavy Industries (MHI) 501 granular-activated carbon (GAC®) combustion turbine generator (CTG) that will be fueled with hydrogen-rich fuel from the gasification plant, and natural gas as a backup fuel;
- a heat-recovery steam generator (HRSG) with duct firing on a combination of hydrogen-rich fuel and Pressure Swing Adsorption (PSA) off-gas; and
- a condensing steam turbine-generator.

The Manufacturing Complex is an integrated complex that will produce approximately 1 million tons per year of nitrogen-based products, including urea, urea ammonium nitrate (UAN), and

anhydrous ammonia for use in agricultural, transportation, and industrial applications. Process units used in producing the low-carbon, nitrogen-based products are the PSA, Carbon Dioxide Purification and Compression, Ammonia Synthesis, Urea, Urea Pastillation and Storage, Nitric Acid, Ammonium Nitrate and UAN units, and associated utilities.

The Prevention of Significant Deterioration (PSD) air permit regulations (40 Code of Federal Regulations 52.21 (j)) require new major sources of air pollution to apply BACT for each "regulated pollutant" for which the potential to emit is significant. BACT must be applied to new emission units that emit one or more of these pollutants. Historically, GHGs have not been considered "regulated pollutants" in the context of PSD and BACT. However, effective January 2, 2011, the USEPA's Greenhouse Gas Tailoring Rule[1] set new GHG pollutant thresholds for evaluation requirements. For the purposes of the PSD program, the pollutant 'GHG' includes the following six component pollutants: CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons, and perfluorocarbons. Of these six GHGs, CO_2 is the dominant GHG emitted for facilities where most of the emissions results from fuel combustion. This is the case for the HECA Project, which will, however, produce smaller emissions of CH_4, N_2O, and SF_6. Accordingly, this BACT analysis focuses on the CO_2 emissions from the Project, but also addresses CH_4, N_2O, and SF_6 emissions.

USEPA's Tailoring Rule requires proposed new projects with carbon dioxide equivalent (CO_2e) emissions greater than 75,000 tons per year, and GHGs on a mass basis greater than 100 tons per year (for steam electrical generating units) to demonstrate the use of BACT for their GHG emissions in the pre-construction permit review. The HECA Project emissions will exceed these thresholds; therefore, this GHG BACT analysis has been prepared for the Project's PSD permit application to comply with the USEPA's GHG Tailoring Rule, and support USEPA's BACT analysis.

The HECA Project will minimize GHG emissions to levels substantially below those of other fossil-fuel power plants and nitrogen-based product manufacturing plants. This is accomplished by a design that employs a number of innovative processes, as well as energy-efficient integration of these processes on a plant-wide basis. One of the most important reasons for the low-carbon footprint of the facility is the removal and capture of 90 percent of the carbon from the syngas, and its transport as a pure CO_2 stream for use in EOR. This practice results in sequestration (storage) of the CO_2 in a secure geologic formation. CO_2 will be transported for use in EOR in the adjacent EHOF, which is owned and operated by OEHI. The OEHI EOR Project will be separately permitted by OEHI through the Department of Conservation, Division of Oil, Gas, and Geothermal Resources, and with SJVAPCD; therefore, the equipment involved in EOR is not included in this BACT analysis. The EOR process results in sequestration (storage) of the CO_2. The HECA Project will be a revolutionary facility by implementing commercial-scale CO_2 capture and sequestration.

The HECA Project will produce low-carbon electricity for delivery to the electrical grid controlled by the California Independent System Operator. This is accomplished using a

[1] Greenhouse Gas Tailoring Rule – Final Rule, USEPA, Published in the Federal Register (pg. 31514) on June 3, 2010, http://www.cdphe.state.co.us/climate/FinalTailoringRule75FR31513.pdf.

combined-cycle turbine that combusts hydrogen-rich fuel as its primary fuel and natural gas for use as a back-up fuel and during start-ups and shut-downs.

The Project incorporates a gasification process to convert petcoke and coal into syngas. The primary components of syngas are carbon monoxide (CO) and hydrogen, and the syngas is further processed in a gas treatment unit to remove acid gases (primarily CO_2) to produce hydrogen-rich fuel. The treatment of syngas is classified as a pre-combustion treatment process that has advantages over a post-combustion treatment process used for pulverized coal power plants. In the pre-combustion treatment process, the treatment and removal of CO_2 and sulfur in syngas occurs at higher pressures and lower volumetric flow rates, which increases the CO_2 capture efficiency, in comparison to post-combustion treatment of exhaust gas in a conventional power plant. The gasification process includes all the facilities required to capture and remove CO_2 and other constituents from the hydrogen fuel, and delivers the CO_2 to OEHI at sufficient pressure and in a suitable physical state for EOR and sequestration.

The removal of CO_2 results in hydrogen-rich fuel production with very low GHG emissions. The HECA Project was intentionally sited in close proximity to a facility that would purchase and use the CO_2 for EOR. The sale of CO_2 for EOR improves the economics of producing low-carbon electricity and nitrogen-based products. The term IGCC generally refers to the use of gasification technology to produce fuel for generation of electricity in a combined-cycle power block. However, products other than power may also be co-produced in an IGCC plant, as is the case for the HECA Project. Taken as a whole, the HECA plant is an innovative integration of existing technologies, creating a unique facility for generating nitrogen-based products, in addition to low-carbon electricity.

An integrated Manufacturing Complex on the HECA site will produce approximately 1 million tons per year of low-carbon nitrogen-based products, including urea, UAN, and anhydrous ammonia for use in agricultural, transportation, and industrial applications. The Manufacturing Complex will use the hydrogen-rich fuel from the gasification unit with the majority of the CO_2 removed to create nitrogen-based products with a significantly lower carbon footprint than a facility for the manufacture of similar products using traditional fossil-fuel sources such as natural gas.

The primary source of GHG emissions from the HECA Project is the combustion (oxidation) of the remaining carbon present in the hydrogen-rich fuel stream in the combined-cycle turbine. The GHG emissions resulting from the combustion of the hydrogen-rich fuel are limited, because this fuel has only 10 percent of the carbon from the raw syngas, with the remaining 90 percent captured in the CO_2 stream, transported to OEHI for EOR and sequestration. A secondary source of emissions will occur intermittently from the gasification block when captured CO_2 needs to be vented during plant start-ups and shut-downs, or when the CO_2 compression, transportation, or injection system is unavailable.

1.1 PURPOSE AND DESIGN OF HECA PROJECT

Generally, BACT is evaluated for the facility as proposed—it does not regulate the purpose or objective for the proposed facility. Put another way, the PSD BACT requirements are not meant to be used to ‘redefine the design of the source’ when considering available control alternatives.

Therefore, it is important to clearly state the fundamental purpose and design of the proposed HECA Project. The discussion in this section is intended to describe the Project objectives in order to provide perspective in determining the range of possible control alternatives that are considered in this BACT analysis, as well as some key Project design features.

The purpose of the Project is not merely the generation of electricity and nitrogen-based products; the following are key interrelated elements of the Project design and purpose:

- Provide dependable, low-carbon baseload electricity to help meet future power needs, and to help back-up intermittent renewable power sources, to support a reliable power grid.
- Enhance the production and availability of in-state nitrogen-based products for use in agricultural, transportation, and industrial applications by producing approximately 1 million tons per year of low-carbon products, including urea, UAN, and anhydrous ammonia.
- Conserve domestic energy supplies and enhance energy security by using abundant solid feedstock, coal, and petcoke to generate low-carbon electricity and manufacture low-carbon nitrogen-based products.
- Mitigate impacts related to climate change by dramatically reducing average annual GHG emissions relative to those emitted from a conventional power plant and/or nitrogen-based product manufacturing facility by capturing, at a rate of 90 percent, and sequestering CO_2.
- Use captured CO_2 for EOR to produce additional oil reserves.
- Demonstrate advanced solid-fuel–based technologies that can generate clean, reliable, and affordable electricity in the U.S., and prove carbon capture and sequestration as a viable method for reducing the carbon footprint of power generation and manufacturing.
- Facilitate and support the development of hydrogen infrastructure in California by supplementing the quantities of hydrogen available for future energy and transportation technologies.

Each of these elements is critical to the objectives of the Project and the design of the source. These are legitimate business goals, important to the Project sponsors. They are not incidental, but essential Project components. Key Project features related to GHG emissions are described below.

Feedstock. Large amounts of petcoke are produced in California and exported overseas. Petcoke and coal are raw materials that are historically cheaper (per British thermal unit [Btu]) and more widely available in the U.S. than natural gas. A purpose of this Project is to use these readily available traditional solid raw materials/fuels, and demonstrate their use for the generation of clean, low-carbon electricity.

Hydrogen is one of the cleanest-burning fuels that can be combusted to generate electricity, especially with regard to GHG emissions. A number of demonstration projects employing similar technology have become operational; however, hydrogen use for this purpose has not yet

been demonstrated in a large-scale application. This Project is revolutionary in the advancement of clean-fuel production and electricity generation, as well as reduction of GHGs through the use of low-carbon fuels. The proposed Project will produce clean, gaseous, hydrogen-rich fuel from some of our most abundant solid fuel resources: petcoke and coal. The production of hydrogen is a key element of the HECA Project.

EOR. The Project will achieve the removal and capture of 90 percent of the carbon from the feedstock fuels, prior to combustion in the turbine or use in the manufacturing of nitrogen-based products. The CO_2 that is captured from the syngas will be used for EOR in the EHOF in Kern County, California. This capture step is significant as a demonstration for U.S. Department of Energy (DOE) funding under their "Clean Coal Power Initiative," as well as integral to the financial objectives of the Project. The use of EOR to recover local petroleum reserves increases U.S. energy independence.

DOE's purpose, aim, and goals in supporting this Project are: "to accelerate the development of advanced coal technologies with carbon capture and storage at commercial-scale. These projects will help to enable commercial deployment to ensure the United States has clean, reliable, and affordable electricity and power." [2]

The HECA facility has been designed specifically with the above objectives in mind. Other means of electrical generation, such as the construction of a conventional natural-gas combined-cycle power plant, or a wind- or solar-generating facility, would not satisfy this Project's fundamental business and technology demonstration goals.

1.2 GHG BACT BACKGROUND

On June 3, 2010, USEPA issued a final rule that "tailors" the applicability provisions of the PSD and Title V programs to enable USEPA and states to phase in permitting requirements for GHGs ("The Tailoring Rule").[3]

GHGs are defined as the aggregate group of the six gases listed in Section 1. The potential applicability of the PSD BACT requirements for GHGs is based on the facility's maximum potential GHG emissions measured in units of CO_2e. CO_2e emissions are defined in the regulation as the sum of the mass emissions of each individual GHG multiplied by its global warming potential (GWP). GWP is a relative measure of how much heat a GHG traps in the atmosphere, compared to a similar mass of CO_2. For purposes of this rule, USEPA defines GWP for CO_2 as 1.0, while it is 21 for CH_4, 310 for N_2O and 23,900 for SF_6.[4] This means that one ton of methane is equivalent to 21 tons of CO_2 for the purposes of global warming regulation.

The Tailoring Rule requires projects receiving a permit after January 2, 2011 to consider BACT for GHG emissions if the source is otherwise subject to PSD, and GHG emissions are above the PSD significance level of 75,000 tons/year CO_2e. In addition, beginning July 1, 2011, GHG

[2] DOE website: http://www.fossil.energy.gov/recovery/projects/ccpi.html.
[3] Greenhouse Gas Tailoring Rule – (75 Fed. Reg. 31514, June 3, 2010) .
[4] Since GWP values may vary, the rule states applicants should use the GWP values in Table A-1 of the Greenhouse Gas Reporting Program (GHGRP) (40 CFR Part 98, Subpart A).

BACT is triggered for projects with significant emissions at a major source even if it would not trigger PSD for any other pollutant. The Project GHG emissions are estimated to be approximately 535,000 tonnes per year; therefore, GHG BACT will apply to the HECA Project.

The requirement for BACT for GHG emissions is relatively new, only becoming applicable to new projects beginning in January 2011[6]. Therefore, there is very little past precedent as to what has been deemed acceptable as GHG BACT for many source categories. However, USEPA has issued several guidance documents to assist in development of appropriate GHG BACT analyses for facilities with some equipment and processes in common with HECA. These include:

- *PSD and Title V Permitting Guidance For Greenhouse Gases*, USEPA Office of Air and Radiation, originally proposed in November 2010, updated March 2011;

- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers, USEPA Sector Policies and Programs Division, Office of Air Quality Planning and Standards, October 2010;

- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry, USEPA, Office of Air and Radiation, December 2010.

In addition, USEPA has published preliminary comments to GHG BACT analyses and draft permits that are submitted by states at http://www.epa.gov/nsr/ghgcomment.html.

These sources, other applications, and draft permits were reviewed to identify the appropriate strategies and control technologies to be included in a GHG BACT. Based on USEPA guidance and determinations to date, the major points of evaluation that should be addressed in a GHG BACT analysis include:

- **Equipment Energy Efficiency** – As stated in their March 2011 guidance, USEPA believes it is important to evaluate the overall energy efficiency of the source. In general, a more energy-efficient technology burns less fuel than a less energy-efficient technology to achieve the same output. Thus, considering the most energy-efficient technologies helps reduce the products of combustion, both GHGs and criteria pollutants.

- **Process GHG Efficiency** – Traditionally, BACT has been evaluated on an emission-unit by emission-unit basis. With GHGs, USEPA is further requiring that the overall efficiency of a facility be evaluated. For example, the HECA Project's main GHG efficiency will occur through the capture and storage of 90 percent of the CO_2 from the raw syngas, plus the designed heat integration of the total facility. The more energy-efficient the process, the less energy will be required, resulting in less GHG emissions.

- **Emission Limits** – USEPA has clearly stated in numerous comment letters that they expect total CO_2e per year emission limits on all permitted sources. In many cases, this limit is set to the full potential to emit of the unit. Nonetheless, it is an imposed emission limit, and the associated monitoring, recordkeeping and reporting requirements are imposed to ensure compliance with the limit.

- **Potentially Applicable Controls** – USEPA is expecting an evaluation of each potentially applicable control measure. This includes switching to a less carbon-intensive fuel, energy efficiency measures (as discussed above), and for the largest sources, add-on controls such as carbon capture and sequestration. However, USEPA expects energy efficiency measures (specific to the source under review) to be the predominant resultant BACT determination. For example—to date, no facilities have been required to use any add-on controls as GHG BACT.

- **More thorough review for larger sources** – At most facilities, a few types of emissions units within a facility typically result in the vast majority of the GHG emissions. Although BACT is required for all sources of a pollutant under PSD review, the level of detail of the analysis is typically scaled proportional to the magnitude of the emissions. In the GHG BACT analysis for projects such as this one, small emission sources such as the infrequently used emergency engines typically require minimal discussion, and result in a finding that use of good combustion practice is sufficient to satisfy BACT.

1.3 KEY PROCESS DESIGN FEATURES RELEVANT TO GHG BACT

This section discusses some of the overall process design features of the Project that help minimize the proposed facility's GHG emissions.

The MHI oxygen-blown dry-feed gasification technology was identified as the best fit to meet the specific requirements of the Project, and to meet key decision criteria, including the lifecycle cost of electricity and reducing technology risk through demonstrated commercial operation with similar feedstock (petcoke and coal), at similar capacity and operating conditions. As part of the design evaluation, other gasification technologies were evaluated, including those of Shell, ConocoPhillips, and General Electric. MHI's oxygen-blown dry-feed design was selected because it is more thermally efficient than slurry feed, and the system has been proven to be reliable and economic.

Mitsubishi's MHI 501 GAC® syngas turbine was selected as the combustion turbine for this Project due to its high efficiency. Further information on the efficiency of this turbine relative to other turbines that were considered is presented in Section 4.1.2.

Another reason that the HECA facility achieves high levels of energy and GHG efficiency is the heat integration incorporated into the process design. Significant heat is generated by the gasification process, and several other plant exothermic chemical reactions. This heat is integrated with, and reused in, other processes that require energy. A significant amount of this heat is used to generate steam at multiple pressure levels. This steam satisfies the requirements of the gas processing units and other users, with the excess steam sent to the power block for electricity generation.

The following outlines the processes from which heat is recovered and reused:

- Heat is recovered from the gas turbine exhaust and used to generate steam in the HRSG. This steam is primarily used to generate power in the steam turbine generator (STG). A

portion of the HRSG flue gas is used to dry the coal and petcoke feedstock upstream of the gasifier unit, instead of using process steam or fuel in a fire heater.

- Heat is recovered from the gasifier by generating steam in the syngas cooler. This steam is used as a source of hydrogen for the gasifier and the shift unit, and also to generate power in the STG.

- Heat is recovered as steam from the shift reaction and recycled to provide hydrogen for the shift reaction. Additional recovered steam and hot water in the shift unit are used for stripping steam, Rectisol® solvent regeneration, boiler feed water heating, syngas heating, and also to generate power in the STG.

- Heat is recovered from the ammonia unit and used to generate steam. This steam provides heat for the urea process and hydrogen for the shift unit.

- Heat is recovered from the UAN unit and used to generate steam. This steam is used to provide hydrogen for the shift unit.

- Heat is recovered from the urea unit and used to generate steam. This steam is used to generate power in the STG.

- Heat is recovered from the sulfur recovery unit (SRU) and used to generate steam. This steam is used mainly in the Rectisol® unit for solvent regeneration and other purposes.

- PSA off-gas is recovered and used as duct-burner fuel to generate additional steam in the HRSG. This steam is used to generate power in the STG.

Below are the principle uses of the steam generated from the recovered heat:

- Power generation in the steam turbine generator.

- Addition of steam to the syngas in the gasification process, a main source of hydrogen for syngas.

- Addition of steam to the syngas to enable the water-gas shift reaction, thereby generating more hydrogen while converting CO to CO_2, to facilitate CO_2 removal from the syngas for sequestration.

- Steam is added to process streams and used for heating in the Air Separation Unit, the Urea Unit, the Acid Gas Removal Unit, the Sour Water Strippers, and Water Treatment Area.

1.4 SUMMARY OF HECA ENERGY EFFICIENCY MEASURES

The HECA design features described in the previous subsection are clearly consistent with the major GHG BACT criteria specified in the USEPA regulations and guidance; that is, energy efficiency through an integrated facility design that promotes capture and reuse of waste heat in many areas, energy efficiency for major plant processes, and energy efficiency as a criterion for

selection of individual equipment. Adoption of this design will enable HECA to produce valuable electricity, a CO_2 stream for EOR/sequestration, and nitrogen-based products on a scale that would otherwise be possible only with substantially higher GHG emissions to the atmosphere. The following sections present detailed information on the expected quantity of GHG emissions, the methodology used to evaluate BACT for all aspects of the HECA operation, and the specific conclusions of this BACT determination.

2. SUMMARY OF FACILITY GHG EMISSIONS AND BACT

2.1 OVERVIEW OF EMISSIONS

The GHG emissions from the Project will occur predominantly in the turbine exhaust from the combustion of uncaptured carbon in the hydrogen-rich fuel, or from venting of CO_2 during start-up and shut-down of the facility and when the CO_2 compression, transportation, or injection system is unavailable. Emissions from the HECA Project are at their lowest when the entire gasification and hydrogen-production facility is operating, and the CTG/HRSG are operating on hydrogen-rich fuel. However, at times, the facility will have to fire on natural gas as a backup fuel.

There are two factors that are uniquely important to a BACT determination for an IGCC/carbon capture and sequestration (CCS) project, and that directly affect the majority of the potential GHG emissions from such a facility:

- The amount of carbon in the combustion fuel to the turbine and HRSG.
- The amount of carbon captured and sequestered from the gasification process as a percentage of the carbon in the syngas.

HECA submits that GHG BACT is capturing 90 percent of the carbon in the raw syngas; this 90 percent rate of capture will be achieved by a Project design and engineering of the capture equipment that is unprecedented for power generation, and exceeds the performance of equipment proposed at other facilities. The removal of carbon, and its subsequent sequestration in EOR and use in urea production, ensures that the generation of electric power and nitrogen-based products starts from a very low carbon syngas, ultimately lowering the GHGs associated with the generation of these products.

GHG BACT is further achieved by selecting and operating equipment capable of combusting fuels that are inherently low in carbon content. HECA achieves low GHG emissions by using only hydrogen-rich fuel, or Public Utilities Commission-regulated natural gas, as backup fuel, to produce electricity. As described in Section 4.1.1 and Table 4-2, both of these fuels are recognized as low in carbon content.

GHG emissions were estimated for three HECA operating scenarios, as described below:

- Early operations, which are expected to last approximately 2 years, during which time the availability of hydrogen-rich fuel will be approximately 65 to 75 percent. During this period, all sources are expected to be operated at maximum operating conditions, including two plant start-ups and shut-downs. The CO_2 vent is included with maximum permitted venting emissions of up to 504 hours at full capacity.
- Mature operations, which are expected to occur after the first 2 years of commercial operation, when the availability of hydrogen-rich fuel will be approximately 85 percent. At this stage, significantly less venting is expected to occur; thus, CO_2 vent emissions are

estimated based on approximately 10 days of venting at 50 percent capacity (or 120 hours of venting at 100 percent capacity). All other sources are operated at maximum operating conditions, including two plant start-ups and shut-downs.

- Steady- state operations, which occur in the same time frame as mature operations; that is, after the 2 years of early operation. In this scenario, emissions are estimated based on maximum operating conditions for all sources for a year, including two start-ups and shut-downs, but no CO_2 venting. Emissions from operation of the CTG/HRSG on syngas are included; no natural gas use is included, except during the start-up and shut-down events.

Table 2-1 presents the annual CO_2e emissions from all stationary sources at HECA in metric tons (tonnes) during the early operations phase. This operational phase represents the maximum total Project annual CO_2e emissions.

Table 2-1
Maximum Annual CO_2e Emissions – Early Operations

Source	Permitted CO_2e Emissions (tonne/yr)
CTG/HRSG H_2-rich fuel and PSA off-gas	269,153
CTG/HRSG natural gas	44,772
CO_2 Vent	174,113
SF_6 circuit breakers	86
Flares	8,257
Thermal oxidizer	5,946
Emergency generators and fire pump	181
Auxiliary boiler	24,782
Ammonia synthesis plant start-up heater	409
Urea absorber vents	116
Nitric acid unit	7,426
Fugitives	35
Total CO_2e Annual Emissions	**535,278**

Source: HECA, 2012.
Notes:
Maximum permitted emissions include periods of start-up and shut-down.
CO_2e = carbon dioxide equivalent
CO_2 = carbon dioxide
CTG/HRSG = combustion turbine generator/heat recovery steam generator
H_2 = hydrogen
PSA = Pressure Swing Adsorption
SF_6 = sulfur hexafluoride

For comparison with the California Senate Bill (SB) 1368 Greenhouse Gases Emission Performance Standard of 1,100 pounds CO_2 per megawatt hour (lb/MWh), GHG emissions and electricity production were calculated following CEC's "Regulations Establishing and Implementing a Greenhouse Gases Emission Performance Standard for Local Publicly Owned Electric Utilities" (CEC, 2012).

The SB 1368 emission calculations include only the annual GHG emissions from each fuel used in any plant component directly involved in electricity production or associated with the sequestration of CO_2. Emissions from electricity production come from the CTG/HRSG when burning syngas, PSA off-gas, and natural gas; and subsequently, the coal dryer. Emissions associated with CO_2 sequestration include the CO_2 vent and fugitives from CO_2 preparation for sequestration. HECA will provide OEHI with sequestration-ready CO_2; that is, no additional compression or processing would be needed to sequester the CO_2 after it leaves the HECA site. The SB 1368 emission calculations do not include SF_6 from the circuit breakers or emissions associated with the Gasification Block (flares, thermal oxidizer), Manufacturing Complex (ammonia synthesis plant start-up heater, urea absorbers, and nitric acid unit), or emissions from the auxiliary boiler, emergency generators, fire pump, and vehicles.

The net electricity production calculated for hydrogen-rich fuel generation includes the net power exported plus the power used on-site in the Manufacturing Complex, minus the steam generated from the Manufacturing Complex. The net power exported is estimated to be 267 MW, although further optimization may result in an output of up to 300 MW. Approximately 58 MW of power will be used in the Manufacturing Complex, and about 5 MW of electricity will be generated from the steam from the Manufacturing Complex. Thus, the net electricity production for SB 1368 purposes with hydrogen-rich fuel generation is 320 MW. The net electricity production for natural-gas generation is 300 MW.

Table 2-2 compares the CO_2 emissions of the Project with the SB 1368 emission standard for three operational scenarios:

- Early operations, which include the maximum permitted emissions for all Project emission sources;
- Mature operations, which includes less CO_2 venting than the early operation scenario; and
- Steady-state operations on hydrogen-rich fuel.

CO_2 emissions from the electricity production at HECA are approximately 225 lb/MWh during steady-state operations on hydrogen-rich fuel. The maximum CO_2 emissions during early operations, including emissions from natural-gas operation, start-up, shut-down, and CO_2 venting, would be approximately 400 lb/MWh.

The maximum emissions are less than one-half of those from a typical natural-gas combined-cycle power plant. In summary, the Project's GHG emissions will be well below both the 1,100 lb CO_2/MWh threshold requirement of SB 1368, and the New Source Performance Standards of 1,000 lb CO_2/MWh threshold proposed by USEPA[5].

[5] USEPA, Standards for Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 40 CFR 60, April 13, 2012.

Table 2-2
Annual CO_2 Emissions for SB 1368 Emission Performance Standard

Operating Parameters	Early Operations (Maximum Permitted)	Mature Operations	Steady-State Syngas Operations
Natural gas operation, hours per year	351	351	15
Hydrogen-rich fuel operation, hours per year	8,108	8,108	8,108
Intermittent CO_2 venting, hours per year	504	120	0
Electricity generated, MWh	2,699,860	2,699,860	2,599,060
Source	**CO_2 Emissions (metric ton/yr)**		
CTG/HRSG hydrogen-rich fuel and PSA off-gas	258,856	258,856	258,856
CTG/HRSG natural gas	44,729	44,729	1,911
CO_2 vent	174,113	41,456	0
Fugitives	31	31	31
Total CO_2 Annual Emissions	**477,729**	**345,071**	**260,799**
CO_2 lb/MWh	390.0	281.7	221.2

Source: HECA, 2012.
Notes:
- Early operations emissions include two periods of start-up and shut-down, natural gas use in the CTG, and 504 hours of CO_2 venting.
- Mature operations emissions include two periods of start-up and shut-down, natural gas use in the CTG, and 120 hours of CO_2 venting.
- During steady-state operations, the CTG and duct burners will fire only hydrogen-rich fuel and PSA off-gas; it includes two start-ups and shut-downs (which includes natural gas), but no natural gas backup use and no CO_2 venting.
- The fugitive CO_2 emissions are from all process areas; therefore, overestimate the emissions from the sequestration process.

CO_2 = carbon dioxide
CTG/HRSG = combustion turbine generator/heat recovery steam generator
lb/MWh = pounds per megawatt hour
MWh= megawatt hour
PSA = Pressure Swing Adsorption

The extent to which carbon capture reduces CO_2 emissions from the facility is illustrated in Figure 1. This figure represents the early operations or maximum permitted emissions. As shown, a substantial majority of CO_2 generated from the gasification process during normal plant operations will be captured product. This product will be transported to OEHI and used for EOR, resulting in sequestration of the CO_2; or used in urea production.

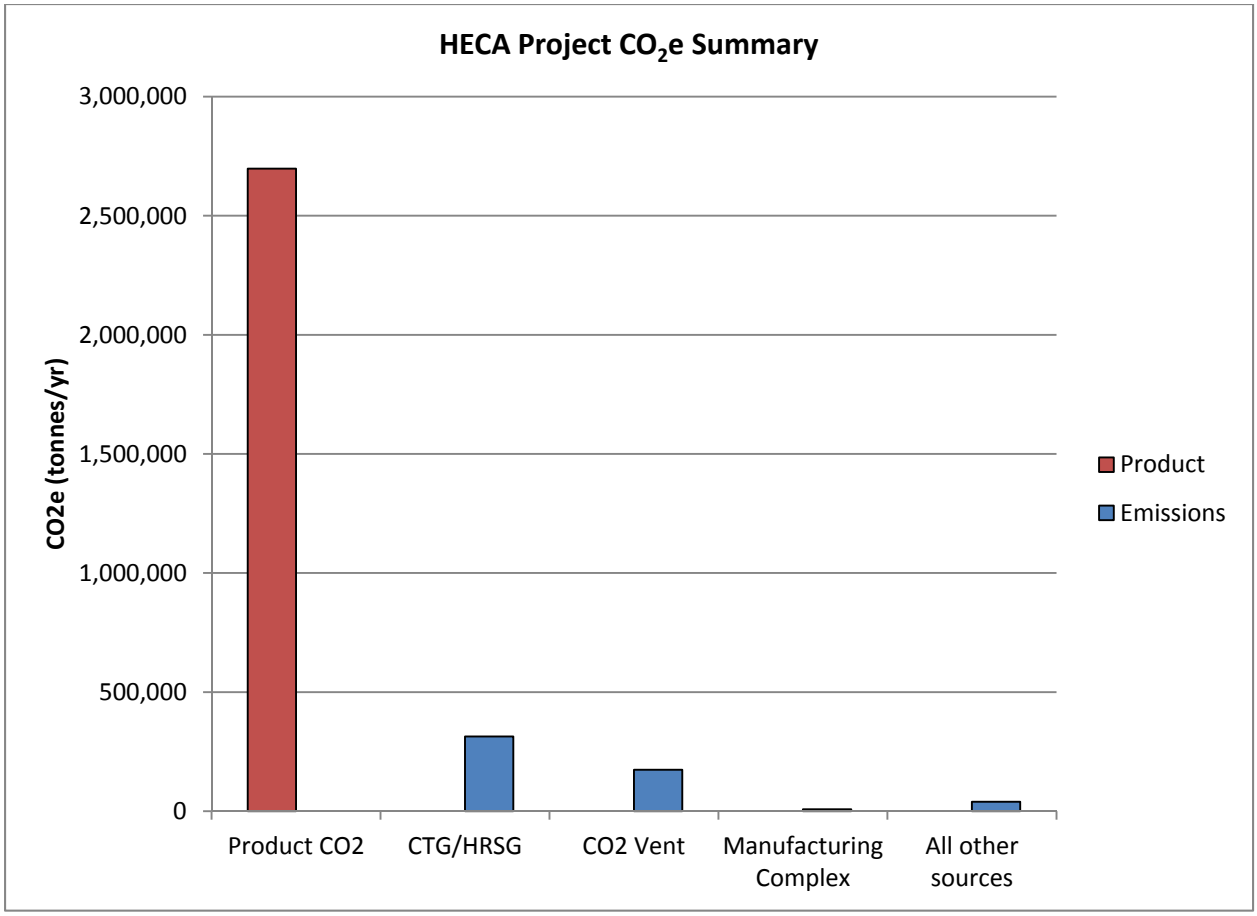

Figure 1 HECA CO_2e Emissions and Product Summary

2.2 EMISSION UNIT–SPECIFIC BACT SUMMARY

A GHG BACT review was conducted for all proposed emission units of the HECA facility. Because the CTG/HRSG and the intermittent CO_2 vent account for the majority of the GHG emissions from the facility, they have been given the most detailed review in this BACT analysis. However, all GHG emissions sources have been addressed. A summary of the proposed BACT is included in Table 2-3.

Section 3 of this BACT analysis provides a brief discussion of the top-down BACT methodology used to evaluate emission control options in this analysis. Details of the proposed BACT determinations for specific HECA equipment are presented in Sections 4 through 11, and the resulting findings are summarized in Section 12.

Table 2-3
Summary of Proposed GHG BACT for HECA

Emission Unit	GHG Pollutant	BACT Determination
Combustion Turbine/HRSG	CO_2, CH_4, N_2O	Pre-combustion carbon capture (90%) on hydrogen-rich fuel Limited use of natural gas as backup fuel
CO_2 Vent	CO_2	Good Operating Practices, Limited hours of operation
Auxiliary Boiler	CO_2, CH_4, N_2O	Use of natural gas fuel, Energy-Efficient Design, Limited Operation, Periodic Tuning
Thermal Oxidizer	CO_2, CH_4, N_2O	Good Operating Practices, Limited Operation
Flares	CO_2, CH_4, N_2O	Flare Minimization Plans, Limited Operation
Nitric Acid Unit	N_2O	Tertiary Control (Catalytic Decomposition)
Ammonia Synthesis Plant Start-up Heater	CO_2, CH_4, N_2O	Good Operating Practices, Use of Natural Gas, Limited Operation
Urea Absorber Vents	CO_2	Good Operating Practices
Emergency Engines	CO_2, CH_4, N_2O	Good Operating Practices Limited Operation
Equipment Fugitive Leaks	CO_2, CH_4	LDAR
Circuit Breakers	SF_6	Enclosed pressure SF_6 circuit breakers with leak detection for equipment failure

Notes:

BACT = Best Available Control Technology
CH_4 = methane
CO_2 = carbon dioxide
GHG = greenhouse gas
HRSG = heat recovery steam generator
LDAR = leak detection and repair
N_2O = nitrous oxide
SF_6 = sulfur hexafluoride

3. BACT PROCESS OVERVIEW/METHODOLOGY

3.1 TOP-DOWN BACT PROCESS

BACT is defined in the Clean Air Act as "*an emissions limitation based on the maximum degree of emissions reduction for each pollutant...which the permitting authority, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through the application of production processes and available methods, systems, and techniques…for control of each such pollutant*."

The "top-down" BACT process involves the identification of all potentially applicable emission control technologies. Evaluation begins with the top or most stringent emission control alternative. If the most stringent control technology is shown to be technically or economically infeasible, or if the associated energy, environmental, or other impacts are severe enough to preclude its use, then it is eliminated from consideration, and the next most stringent control technology is similarly evaluated. This process continues until the BACT option under consideration cannot be eliminated by the considerations described above. The top control alternative that is not eliminated is determined to be BACT. This process commonly involves the following five steps:

- **Step 1**: Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation.
- **Step 2:** Eliminate all technically infeasible control technologies.
- **Step 3:** Rank remaining control technologies by control effectiveness and tabulate a control hierarchy.
- **Step 4:** Evaluate most effective controls and document results.
- **Step 5:** Select BACT, which will be the most effective practical option not rejected based on economic, environmental, and/or energy impacts.

BACT is not intended to prohibit increased emissions, but merely to assure that reasonable controls are employed on new or modified sources of large projects.

4. COMBUSTION TURBINE/HRSG GHG BACT ANALYSIS

As stated, the HECA Project is designed to generate electricity through the combustion of low-carbon fuel in a gas-fired turbine. After removal of the majority of the carbon from the syngas in the acid gas recovery (AGR) system, the Project combustion turbine will fire a hydrogen-rich fuel to generate electricity. Natural gas serves as a backup fuel to allow continuing export of electrical power when hydrogen-rich fuel is not available, and during start-up or shut-down. Excess heat in the turbine exhaust will be recovered as steam in the HRSG and used to generate additional electricity with a steam turbine in combined-cycle mode. Produced power will be used on-site to meet the facility's internal load, routed to the Manufacturing Complex for nitrogen-based product manufacturing, and exported to the electrical grid. Net electrical generation is approximately 300 MW. A portion of the HRSG flue gas will be used to dry the coal and petcoke, and will be emitted from the coal dryer stack. The following analysis only discusses the GHG emissions generated from the CTG/HRSG, because no GHG emissions will be generated from the coal dryer, even though the emissions will be emitted from both the HRSG and coal dryer stacks.

4.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

Four GHG control possibilities have been identified with potential applicability to the proposed combustion turbine:

- Pre-combustion CO_2 Capture/Low-Carbon Fuels;
- Energy-Efficient Turbine Design;
- Post-combustion CO_2 Capture and Sequestration; and
- Limited Operation on Natural Gas.

Each of these control options is discussed below.

4.1.1 Pre-Combustion CO_2 Capture/Low-Carbon Fuel

CO_2 is a product of combustion generated by any carbon-containing fuel. Virtually all the carbon in a fuel becomes CO_2 in the combustion exhaust; therefore, fuels that have lower carbon content, relative to their overall heating value, emit less CO_2. The HECA Project generates syngas from coal and petcoke feedstock, and removes 90 percent of the carbon to generate a hydrogen-rich fuel, with very low carbon content, which is then used to fuel the turbine. The plant is designed to capture 90 percent of the carbon in the total syngas flow, and this will exceed the capture proposed for similar facilities, as discussed below.

DOE[6] evaluated three proposed IGCC power plant configurations with carbon capture, and determined that the GE Energy facility could achieve 90.2 percent reduction of CO_2 in syngas through two stages of sour gas shift (SGS) with Selexol, the Conoco Phillips facility could

[6] Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

achieve 88.4 percent reduction of CO_2 in syngas with three stages of SGS, and the Shell facility could achieve 90.8 percent reduction of CO_2 in syngas with two stages of SGS. These capture rates are design values and have not been proven in practice; HECA is proposing a capture rate that is similar or better.

There are currently two existing operational IGCC facilities in the United States: Duke Energy, Wabash River Generating Station in West Terre Haute, Indiana; and Tampa Electric Company, Polk Power Station in Mulberry, Florida—neither facility employs pre- or post-combustion CCS.

Of the recently permitted IGCC facilities, the Summit Texas Clean Energy Project IGCC Facility in Odessa, Ector County, Texas, claims that 90 percent of the CO_2 in the syngas will be captured for CCS in EOR. For the Taylorville Energy Center near Taylorville, Illinois, there is no requirement for pre- or post-combustion CCS, and the Illinois Environmental Protection Agency determined that "there is no basis for concluding the BACT limit for carbon capture should be 90 percent, which is wholly arbitrary and not supported by material in the record."[7]

The Hyperion Energy Center and the South Dakota Department of Environment and Natural Resources both agreed that CCS was not BACT because it was not feasible due to high costs. The Hyperion Energy Center will use imported solid fuels (petcoke and/or coal) to generate power in its operating "maximum coke design" scenario. The Indiana Gasification Project in Rockport, Indiana, which will generate synthetic natural gas from Illinois coal, is proposing to capture 90 percent of the CO_2 from the SNG, although only 80 percent of that CO_2 will be used in EOR and ultimately sequestered, while the remainder will be vented.

The 90 percent CO_2 capture rate that HECA proposes meets or exceeds other similar facility capture rates when CO_2 capture has been proposed. This capture and sequestration significantly reduces GHG emissions over other IGCC facilities that will not sequester CO_2.

A portion of clean, hydrogen-rich fuel from the AGR Unit is sent to the PSA Unit to generate a high-purity hydrogen gas stream for use as a feedstock to the Ammonia Synthesis Unit. The off-gas from the PSA unit is compressed and sent to the HRSG for use as duct-burner fuel. The combustion turbine exhaust gas, supplemental hydrogen-rich fuel for duct-firing, and PSA off-gas for duct-firing are used as energy input into the HRSG. Typical compositions of the hydrogen-rich fuel stream and PSA off-gas at HECA are shown below in Table 4-1.

This high hydrogen content and low carbon content is achieved through the unique process configuration proposed by this first-of-its-kind facility. These low fuel-carbon levels represent the practical limits feasible for use in the proposed turbine and duct burners.

This HECA fuel treatment process constitutes "pre-combustion" carbon capture. The use of this process reduces the carbon content of the fuel to the combustion turbine/HRSG, and results in exceptionally low GHG emissions compared with comparable equipment using conventional

[7] Illinois Environmental Protection Agency, Bureau of Air Permit Section, Responsiveness Summary for Public Questions and Comments on the Construction Permit Application from Christian County Generation for the Taylorville Energy Center in Taylorville, Illinois, April 2012.

Table 4-1
Typical Syngas Fuel Composition

Component	Hydrogen-rich Fuel Mole (%)	PSA Off-gas Mole (%)
Hydrogen	83.8	23.8
Carbon Monoxide	1.9	9.1
Carbon Dioxide	1.5	7.1
Methane	1.1	5.0
Nitrogen	11.6	54.4
Argon	0.1	0.6

Note:
PSA = Pressure Swing Adsorption

fossil-fuels levels. The Project will capture 90 percent of the carbon in the syngas whenever the gasification system is operating. The captured carbon will be sold as CO_2 for EOR, resulting in sequestration, and therefore will not be emitted to the atmosphere. Due to the close proximity of a buyer for the CO_2 product for EOR, pre-combustion carbon capture resulting in sequestration is a feasible option for the HECA Project.

In addition to the use of hydrogen-rich fuel, the turbine will also be capable of using natural gas as a backup fuel. The Project needs the flexibility to use natural gas for periods when the gasification system is shut down or upset, and for facility start-ups and shut-downs. Natural gas also has lower-carbon content relative to most other fossil fuels. Table 4-2 illustrates CO_2 emission factors for a variety of conventional fuels, compared to the fuels proposed for this Project.

As the above emission factors illustrate, the HECA hydrogen-rich fuel and PSA off-gas will result in as low or lower CO_2 emission rates than units using other conventional fossil fuels. Although coal and petcoke cannot be used directly in the HECA combustion turbine, their comparison helps further illustrate how the Project's conversion of these solid fuel feedstocks to an inherently low-carbon, hydrogen-rich fuel allows these abundantly available solid fuels to be used in an environmentally efficient manner. The flexibility to use natural gas as a backup fuel, the lowest-carbon conventional fossil fuel, is important to improve the availability and reliability of this power generation on this first-of-a-kind unit.

As shown in Table 2-2, the maximum CO_2 power-related emissions, including emissions from natural-gas operation, start-up, shut-down, and CO_2 venting, would be approximately 400 lb/MWh. These maximum emissions are less than one-half of those from a typical natural-gas combined-cycle power plant, and approximately one-sixth to one-tenth of those from pulverized coal power plants.

The use of low-carbon, hydrogen-rich fuel, with 90 percent of carbon removed, and natural gas as a backup fuel is a highly effective method of reducing CO_2 emissions. It is technically feasible and is inherent to the design of the proposed facility.

Table 4-2
CO_2 Typical Emission Factors from Stationary Combustion Sources by Fuel

Fuel	Pounds CO_2 per Million Btu
Petroleum Coke[1]	225
Coal[1]	210
Distillate Oil[1]	161
Natural Gas[1]	116
HECA hydrogen-rich fuel and PSA off-gas[2]	25

Notes:
[1] Source: U.S. Energy Information Administration, http://www.eia.doe.gov/oiaf/1605/coefficients.html.
[2] Source: Project estimates (includes only CO_2 in HRSG exhaust stream for the combination of hydrogen-rich fuel and PSA off-gas expected to be used annually)
Btu = British thermal unit
CO_2 = carbon dioxide
HECA = Hydrogen Energy California LLC
PSA = Pressure Swing Adsorption

4.1.2 Energy Efficiency (Turbine Design)

Fuel selection is the most important consideration in reducing power plant GHG emissions. Following this, another key component for reducing CO_2 emissions is energy efficiency. Because CO_2 emissions are directly related to the amount of fuel fired, the more efficient the combustion process, the lower the fuel quantity required, and the lower the GHG emissions that result.

Combined-cycle combustion-turbine generators use an inherently energy-efficient design. A typical configuration is the use of a combustion turbine to generate electricity, with the waste heat in the exhaust used to generate steam in the HRSG. This steam is then expanded in a steam turbine to generate additional electricity, which directly offsets additional firing to obtain the same output.

In this unique Project, the GHG emissions from the combustion turbine are not as greatly affected by the turbine system's overall efficiency, due to the use of a fuel containing very low carbon content. Nevertheless, HECA has proposed an efficient turbine system design.

Mitsubishi will provide a full commercial offering for the MHI 501 GAC® turbine for this Project that includes operation on both hydrogen-rich fuel and natural gas as backup fuel. The MHI G-Class turbines have been among the best for economic, efficient, reliable, clean power generation for many years. MHI has continued to evolve its "G" class technology, with the

performance of the current 501 GAC® improved compared with its predecessor. Although this will be the first commercial application of this turbine in hydrogen-rich fuel service for electricity generation, the operating experience of the MHI G-Class turbines in conventional natural-gas combined-cycle service and the MHI 701DA in the Fukushima demonstration IGCC project are key to its selection for this Project.

GE and Siemens offer F-class hydrogen gas turbines, and their offers are expected to be approximately 2 percent less efficient compared to the MHI 501 GAC® hydrogen-rich turbine, because the G-class turbine is a newer, more-efficient design. Next-generation turbines such as J-Class turbines are not available for the Project, because they have not been offered by turbine suppliers for hydrogen-rich fuel. HECA is using the most efficient turbine currently offered by vendors for hydrogen-rich fuel service.

Because the proposed system is designed to optimize IGCC heat integration on hydrogen-rich fuel, operation of the CTG/HRSG using the alternate natural-gas fuel will be somewhat less efficient than a typical natural-gas combined-cycle application. Nevertheless, the specific turbine system is designed specifically for, and required for, the primary operation of the facility— an IGCC with hydrogen-rich fuel.

4.1.3 Post-Combustion Carbon Capture and Sequestration

As explained in Section 4.1.1, the Project provides "pre-combustion" carbon capture. As a result, the exhaust stream from the proposed combustion turbine, when firing the hydrogen-rich fuel, will have substantially lower CO_2 content than standard fossil fuels. The lower exhaust CO_2 content makes "post-combustion" CO_2 capture considerably less practical and less achievable than for a high-CO_2 stream. Capture of the CO_2 from the turbine exhaust is significantly more difficult than in the pre-combustion synthesis gas stream for two predominant reasons: Low concentration, and low pressure.

Lower concentrations and low pressures mean that a very large volume of gas needs to be treated in order to recover each pound of CO_2. This fact is even more relevant for the proposed HECA turbine when firing its primary fuel—hydrogen-rich syngas. Additionally, these same process factors decrease the driving force for the CO_2 to be adsorbed into a solvent. Low-pressure systems entail higher energy demands, because solvents designed to absorb significant CO_2 at low pressures are difficult from the standpoint of subsequent desorption to regenerate and reuse the solvent. Also, a low-pressure absorption system would create a low-pressure CO_2 stream, which would require even greater energy demand for compression to transport the CO_2 for EOR. (Note: The proposed Rectisol® system desorbs the CO_2 at multiple-staged pressures, minimizing the compression requirements.)

Post-combustion carbon capture is a relatively new concept, and is still in the developmental phase and not yet widely practiced—and never on a hydrogen-rich fuel-combustion turbine exhaust.

At the Florida Power and Light natural gas power plant in Bellingham, Massachusetts, a post-combustion carbon-capture system called an Econamine FG process was operated from 1991 to 2005. Although the Econamine process claims it can capture CO_2 from turbine exhaust with low

CO_2 and high oxygen concentrations, the CO_2 content of the natural-gas exhaust stream is approximately 10 times higher than the hydrogen-fuel exhaust at HECA. The hydrogen-rich exhaust stream has an extremely low CO_2 content.

Although chemical solvent/scrubbing systems have been used commercially at some industrial facilities, the implementation of post-combustion CO_2 capture systems with this combustion turbine is not considered a commercially available option at this time. No potentially viable technology systems have been tested in post-combustion service at a scale similar to that of this turbine exhaust stream. Developments are generally at an early stage, and the risks to successful commercialization are still high.

For the reasons cited above, the application of post-combustion capture to this particular Project, which already employs 90 percent pre-combustion capture, would be impractical.

Although post-combustion carbon capture has been conducted for natural gas turbines on a limited, trial basis, HECA intends to use natural gas only as a backup fuel for the turbine. Thus, the extremely limited operations with natural gas would not justify the cost of post-combustion carbon capture.

The fact that the HECA facility will have a Rectisol® AGR system and a commercial outlet for captured CO_2 does not sufficiently improve the feasibility of carbon capture and sequestration for post-combustion systems. Rectisol® would not be capable of capturing CO_2 in the low-pressure turbine exhaust. Rectisol® only works in very high-pressure systems where the high partial pressure of the CO_2 allows it to be physically captured by the solvent.

No recently permitted IGCC facilities propose use of post-combustion capture and sequestration. Based on the lack of any commercial demonstrations of carbon capture on a hydrogen-rich fuel turbine exhaust, the very low concentrations of CO_2 in the turbine exhaust when firing the primary fuel, and the limited secondary natural gas fuel usage, post-combustion CO_2 capture for the turbine is not a technically feasible option, and therefore is not carried forward in the subsequent steps of this BACT analysis.

4.1.4 Limited Operation on Natural Gas

Natural gas will be used during start-up and shut-down of the combustion turbine, and during periods of unplanned equipment outages for up to 2 weeks per year. Because only two facility start-ups and shut-downs are planned per year, emissions from all sources will be minimized by limiting plant start-ups and shut-downs. GHG emissions during start-up and shut-down are based on the amount of fuel burned; thus, minimizing the duration of these events will minimize the GHG emissions.

Natural gas usage in the turbine is based on 15 hours in start-up and shut-down mode per year, plus 336 hours of normal turbine operation, with no natural-gas duct firing.

4.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

The most effective control technologies for reduction of CO_2 emissions from the Project combustion turbine include the use of pre-combustion capture, low-carbon fuel, and efficient turbine design, plus limiting the operation on natural gas. These Project elements are included in the base design of the HECA Project. No other technically feasible technologies are available for this source at this time.

4.3 STEP 5 – SELECTION OF GHG BACT FOR COMBUSTION TURBINE/HRSG

The proposed operation with pre-combustion capture/low-carbon fuel and efficient turbine design represents BACT for the proposed combustion turbine. Use of the backup fuel natural gas will be limited. Project emissions of GHGs are inherently low, due to the fact that the facility is designed to capture 90 percent of the fuel carbon prior to combustion in the turbine. Further controls of this source are not warranted or achievable.

The proposed GHG BACT for this unit is the use of an efficient turbine for this hydrogen-rich fuel service, with natural gas for backup, and the pre-combustion capture of 90 percent of the total carbon in the syngas and the limitation of natural gas use. This will be demonstrated by monitoring the flow rate and carbon content in the captured CO_2 stream, and the flow and carbon content of the hydrogen-rich fuel combusted in the CTG/HRSG. Natural gas flow to the turbine will also be monitored.

Emissions from the low-carbon fuel used in the CTG/HRSG will be demonstrated through compliance with SB 1368; HECA will calculate the CO_2 emissions per MWh from power production to compare against the Emission Performance Standards of 1,100 lb/MWh. HECA proposes that the maximum CO_2 power-related emissions, based on the SB 1368 calculation methodology, would be less than or equal to 400 lb/MWh.

The demonstration of pre-combustion capture at a rate of 90 percent will exceed that of any facility currently in operation, and constitutes BACT for this unique and first-of-a-kind facility.

5. CO_2 VENT BACT ANALYSIS

In addition to removing sulfur from the syngas, the plant's AGR system will capture 90 percent of the carbon in the raw syngas during steady-state operation, and separate it into a high-purity CO_2 product stream. This CO_2 stream is an important product of the facility. A portion of the captured CO_2 will be used in the production of urea, and the majority will be compressed and transported by pipeline to the customer, OEHI, which will use it for EOR in the nearby existing EHOF, resulting in sequestration. The HECA Project site was selected, in part, due to its close proximity to the EHOF. The sale of this product for use in EOR is important to the Project economics, and sequestration in connection with EOR is an inherent part of the basic design purpose of this Project.

Because the CO_2 product from this facility is an inherent part of the Project's economics, the plant will be designed to provide reliability of the purification and compression facilities needed to deliver it to the transfer point for use by OEHI. However, it is not possible to guarantee 100 percent availability of the pipeline and EOR systems. The CO_2 stream will need to be vented during breakdowns, malfunctions, and/or upsets, such as outages of the CO_2 compressor or pipeline; or when OEHI is unable to accept the CO_2 stream, and during gasifier start-up and shut-downs. The CO_2 compressor will use power generated by the CTG/HRSG; thus, no GHG emissions are associated with this source. The flow rate during these periods of venting will be measured, and will be included in the HECA overall recordkeeping requirements under the Project's applicable CEC and SJVAPCD permits. In addition, venting duration will be indirectly limited by separate emissions limits on CO, volatile organic compounds (VOC), hydrogen sulfide (H_2S), and carbonyl sulfide (COS) emissions from this unit in the SJVAPCD permit.

Approximately 2.6 million tonnes/yr of CO_2 will be transported and sold to OEHI. The sale of this stream for EOR and sequestration serves the dual beneficial purposes of providing for long-term geological storage of the CO_2, while also increasing the oil production from these existing oil wells, thus enhancing domestic oil supplies.

This section of the BACT analysis discusses potential controls for the CO_2 vent stream during the intermittent periods when the CO_2 product stream cannot be delivered to OEHI.

5.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

The vent stack will allow for infrequent venting of produced CO_2 when the CO_2 EOR injection system is unavailable or unable to export due to breakdowns, malfunctions, and/or upset conditions; or during gasifier shut-downs and subsequent restarts. The CO_2 vent exhaust stream will consist mostly of CO_2, with only trace (parts per million) levels of certain criteria pollutants and other compounds.

Possible controls identified for this source include:

- Minimize Venting – Good operating practices of the compression and transportation system; and
- Alternative storage for captured CO_2.

Each of these methods, and their feasibility for this Project, are discussed below.

5.1.1 Minimization of Venting

GHG emissions from this source are proposed to be controlled by limiting venting to periods when the compression and transportation systems are unavailable, and during gasifier start-up and shut-down. The use of good operating practices will minimize interruptions to the compression and transportation systems. These practices include regular maintenance of the compression and transportation system. Efforts to assure a high reliability include selection of a compressor with a proven record in similar service, and selection of the highly reliable AGR technology Rectisol®, which has been in use since 1949, and employed in over 85 facilities worldwide.

5.1.2 Alternative Storage

For periods when the pipeline cannot receive the CO_2 stream, there are no other realistic alternative CO_2 storage opportunities. Building tanks for short-term storage of this product would not be practical or safe. Even compressed to 200 pounds per square inch gauge (psig) (the pressure of a standard propane tankcar), the plant's daily production of CO_2 would require storage space equivalent to more than 2,000 pressurized railcars (assuming 30,000 gallons each). The only reasonable storage option for large volumes of CO_2 is underground geological structures (such as the proposed EOR sales outlet).

5.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

As discussed above, the only feasible GHG control alternative for this emissions source is good operating practices of the HECA CO_2 compression and transportation systems. Therefore, this is proposed as the top control technology. There are no negative impacts of this option.

5.3 STEP 5 – SELECTION OF GHG BACT FOR CO_2 VENT

As the only technologically feasible option, BACT for GHG emissions from the CO_2 vent is proposed to be good operating practices, and limited operations of the HECA CO_2 compression and operating systems**.** Because this is an important power sales attribute (power sold in California must have CO_2 emissions less than the SB 1368 Emission Performance Standards) and CO_2 product revenue source, there is an inherent and strong financial incentive for HECA to perform at a high level of reliability. HECA proposes to limit venting to a maximum of 174,113 tonnes per year, which is equivalent to 504 hours at maximum venting rate for this unit. This will be demonstrated by monitoring the flow rate to the CO_2 vent. The original SJVAPCD permit restricted venting of this stream to periods when the compression and transportation system is unavailable due to breakdowns, malfunctions, and/or upsets; or during a gasification block start-up or shut-down, and limited the venting duration indirectly by separate emissions limits on CO, VOC, H_2S, and COS emissions. It is expected the revised SJVAPCD permit will contain similar conditions.

6. AUXILIARY BOILER GHG BACT ANALYSIS

The auxiliary boiler is a pre-engineered package boiler that will provide steam for pre-start-up equipment warm-up, and for other miscellaneous purposes when steam from the gasification process or HRSG is not available. The auxiliary boiler will be designed to burn pipeline-quality natural gas at the design maximum fuel flow rate of 213 million British thermal units per hour (MMBtu/hour) (high heating value), but will have a much lower average firing rate. The significant heat efficiency and process integration steps discussed in Section 1.3 allow for the auxiliary boiler to be off during normal steady-state, full plant operation. Average annual firing, allowing for start-ups, shut-downs, and partial load situations, will be no more than 53.3 MMBtu/hr or 466 billion Btu per year.

6.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

A review of the Reasonably Available Control Technology/BACT/Lowest Achievable Emission Rate Clearinghouse (RBLC) from 2002 to March 2012 showed two BACT determinations on gas-fired heaters or boilers. Neither of these required add-on controls. The Nine Mile Point Electric Generating Station (LA-0254) included a 338 MMBtu/hr gas-fired auxiliary boiler, which specified proper operation and good combustion practices as BACT for CO_2, N_2O, and CH_4. In addition, the Port Dolphin Energy facility (FL-0330, 12/1/11) included four natural gas boilers rated at 278 MMBtu/hr each, which specified boiler tuning, optimization, instrumentation, and controls, insulation, and turbulent flow as BACT for CO_2.

Based on the above entries in the RBLC, as well as USEPA guidance for boilers, potentially applicable GHG control technologies considered for the auxiliary boiler include:

- Post-combustion CO_2 capture and sequestration;
- Energy-efficient overall facility design—allowing limited boiler firing;
- Use of lower-carbon fuels;
- Energy-efficient boiler design (air preheater, economizer, condensate recovery, etc.);
- Periodic burner tuning (to maintain efficiency); and
- Limited operation.

6.1.1 Post-Combustion CO_2 Capture and Sequestration

As discussed under the analysis for the combustion turbine, post-combustion CO_2 capture is a relatively new concept, and rarely used on combustion systems. Unlike the gasification AGR system, which generates a concentrated CO_2 stream ideal for capture, capture of the CO_2 from the boiler exhaust is significantly more difficult because the CO_2 is at a low concentration and low pressure. Also, because the average firing rate of this boiler will be no more than 53.3 MMBtu/hr, there is very little CO_2 to be captured.

CO_2 post-combustion capture systems for small- to medium-sized combustion systems are not economically viable as supported by the USEPA GHG BACT guidance document[8], which recommends that Carbon Capture and Sequestration only needs to be considered in a BACT analysis for very large CO_2 sources and industrial facilities with high-purity CO_2 streams (cement production, iron and steel, etc.). For example, in Appendix F of this guidance document, the USEPA presents an example BACT for a 250 MMBtu/hr natural-gas–fired boiler, in which carbon capture is not even listed in step 1 of the BACT analysis as a potentially available option[9]. The HECA Project auxiliary boiler will have a maximum heat rate of 213 MMBtu/hr, which is even smaller than this USEPA example, and will have an average fuel consumption rate of only 53.3 MMBtu/hr.

Therefore, post-combustion CO_2 capture for the small, limited-use auxiliary boiler is not a technically feasible option, and it has not been carried forward in the subsequent steps of this BACT analysis.

6.1.2 Energy-Efficient Facility Design

The overall heat integration and energy efficiency measures incorporated into the plant design effectively eliminate the need for any auxiliary boiler firing during normal steady-state operation. These are the most significant measures, resulting in the low GHG emissions from this source. Due to these plant design features, the auxiliary boiler will operate in "standby" service most of the time. The original SJVAPCD permit restricts the use of this emission source by limiting its allowable annual average fuel firing rate. HECA requests that the annual firing limit for this unit be established as 466 billion Btu per year (53.3 MMBtu/hr 12-month average), which is consistent with the Project emissions calculations.

6.1.3 Lower-Carbon Fuel

Carbon dioxide is a product of combustion generated with any carbon-containing fuel. The preferential use of natural gas in the auxiliary boiler, a lower-carbon fuel, is a highly effective method of reducing CO_2 emissions versus use of solid fuels. The HECA Project auxiliary boiler will fire natural gas as a lower-carbon fuel, despite the fact that coal and/or petcoke are available on the site. The Project considered the use of the produced hydrogen-rich fuel, but found this to be infeasible because this fuel stream will be unavailable during most of the periods when this boiler would be in use (start-ups, shut-downs, upsets). Also, because reliability of this boiler is important for emergency situations, the use of more reliable natural gas is preferred, even when the hydrogen-rich fuel is available.

6.1.4 Boiler Energy Efficiency

Another opportunity for reducing GHG emissions is to maximize the energy efficiency of the boiler. Because CO_2 emissions are a direct result of the amount and rate of fuel fired (for a given

[8] PSD and Title V Permitting Guidance For Greenhouse Gases, November 2010, USEPA Office of Air and Radiation, pp. 34, 35.

[9] PSD and Title V Permitting Guidance For Greenhouse Gases, November 2010, USEPA Office of Air and Radiation, p. F-1.

fuel), a more efficient boiler requires less fuel and produces lower GHG emissions than a less efficient one.

Although the use of this boiler results in only minimal fuel consumption and GHG emissions, three energy efficiency measures have been identified that may be applied to this combustion source.

Heat Recovery with an Economizer: to recover additional heat from the boiler exhaust to preheat boiler feed water. This reduces the heat energy required from fuel combustion to heat the boiler water. (Note: for some types of boilers, an alternative exhaust heat recovery step could be using the hot exhaust in an air preheater, instead of an economizer. However, air preheaters are very unusual for natural gas boilers, and are no more effective in recovering exhaust heat than a boiler feed water economizer. Additionally, preheating the air could slightly increase nitrogen oxides emissions. Consequently, use of an economizer has been considered, rather than an air preheater.)

Condensate Recovery: by returning the hot steam condensate from the process as feedwater, thereby decreasing the boiler heat load.

Inlet air trim controls: can limit excess air by using a stack CO or oxygen (O_2) monitor and automatically adjusting inlet air. Limiting the excess air enhances efficiency and reduces emissions by reducing the volume of air that needs to be heated in the combustion process.

The auxiliary boiler is proposed to include Heat Recovery Economizer and Condensate Recovery, but not Inlet Air Controls. Optimizing excess air can be a cost-effective measure on large boilers, but is uncommon for small boilers, or boilers with limited use. According to the USEPA's Boiler White Paper, manufacturers estimate that a 1 percent thermal efficiency increase can be achieved with oxygen trim control.[10] The firing of this auxiliary boiler is limited to no more than 213 MMBtu/hr and 466 billion Btu per year, which is equivalent to an annual average firing rate of 53.3 MMBtu/hr. At this rate, an improvement of 1 percent thermal efficiency (resulting in 1 percent lower firing) would reduce annual GHG emissions by only about 250 tons per year. Due to the small size of this boiler and the overall small emissions from this source, the application of inlet air controls is not justified, and is not considered further in this analysis.

One other possible boiler energy efficiency step would be to install a heat exchanger for recovery of the heat from boiler blowdown. However, the relatively small size of this boiler (on an average load basis) and its infrequent operation does not justify the incremental costs for this measure. (Note: this is consistent with the example presented in Appendix F of USEPA's November 2010 GHG BACT Guidance[11], in which blowdown heat recovery was not cost effective for a 250 MMBtu/hr natural gas boiler.)

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[10] Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers, USEPA, October 2010, p. 14.

[11] PSD and Title V Permitting Guidance For Greenhouse Gases, November 2010, USEPA Office of Air and Radiation, p. F-2.

The auxiliary boiler make and model have not yet been selected; however, based on experience, and the boiler features specified, such as an economizer (boiler feed water heater) and condensate recovery, it is expected that the boiler efficiency will be approximately 90 to 92 percent, lower heating value (equivalent to about 81 to 83 percent, higher heating value).

6.1.5 Periodic Boiler Tuning

A combustion system can drift over time from its optimum setting. HECA proposes to tune the combustion system every 2 years by conducting a visual check by an experienced boiler engineer to ensure that everything is in working condition and set per manufacturers' recommendations, or optimum settings developed for the particular boiler.

6.1.6 Limited Operation

The auxiliary boiler operation will be limited to 25 percent capacity annually. This equates to an annual average fuel firing rate of 466 billion Btu per year.

6.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

After eliminating the infeasible technologies for the limited-use auxiliary boiler, the remaining control options are:

- Use of a lower-carbon fuel, natural gas;
- Energy-efficiency measures (Economizer and condensate recovery);
- Periodic tuning; and
- Limited operation.

6.3 STEP 5 – SELECTION OF GHG BACT FOR AUXILIARY BOILER SOURCES

BACT is proposed to be use of natural gas as a fuel; design with economizer and condensate recovery as energy-efficiency measures; periodic tuning; and limited operation. HECA proposes limiting the auxiliary boiler allowable annual average fuel firing rate to 466 billion Btu per year. Compliance with this limit will be demonstrated by monitoring the natural gas flow rate to the auxiliary boiler. Based on the existing SJVAPCD permit, it is expected the revised SJVAPCD permit will restrict the annual average fuel firing rate to 466 billion Btu per year, and also limit the criteria pollutant emissions, thus effectively limiting the annual usage of the auxiliary boiler.

7. TAIL GAS THERMAL OXIDIZER GHG BACT ANALYSIS

Associated with the operation of the sulfur recovery process, the Project will incorporate a thermal oxidizer on the tail-gas treating unit. The thermal oxidizer will serve as a control device to oxidize any remaining H_2S (after scrubbing) and other vent gas that is generated during start-up, shut-down, and times of non-delivery of CO_2 product. In addition, miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) are directed to the thermal oxidizer during operation to prevent nuisance odors. The thermal oxidizer operates at high temperatures, and provides sufficient residence time in order to ensure essentially complete destruction of reduced sulfur compounds like H_2S to SO_2.

The thermal oxidizer will continuously fire 13 MMBtu/hr of natural gas to maintain the required operating temperature for proper thermal destruction. The thermal oxidizer fires an additional 80 MMBtu/hr of natural gas for the periodic oxidation of vent gas during SRU start-ups (up to 48 hours per year). The GHG emissions from this source represent approximately 1 percent of the total CO_2e that will be emitted from the facility. The following sections briefly analyze potential GHG controls for this source.

7.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

Potentially applicable GHG control technologies considered for the tail-gas thermal oxidizer include:

- Use of lower-carbon fuel;
- Energy-efficient design;
- Post-combustion CO_2 capture and storage; and
- Limited operation.

7.1.1 Lower-Carbon Fuel

The thermal oxidizer will fire natural gas as a lower-carbon fuel. The hydrogen-rich fuel that is generated at the facility and used in the combustion turbine is not available during start-ups, and is not a suitable failsafe fuel source for the thermal oxidizer.

7.1.2 Energy Efficiency

The thermal oxidizer is a very small source. It has no air inlet controls or heat recovery because it has only a simple, small burner, which precludes these control options as technically or economically feasible measures for this unit. No applicable energy-efficiency measures are identified to carry forth in the BACT analysis.

7.1.3 Carbon Capture & Sequestration

Post-combustion CO_2 capture is not technically feasible for the thermal oxidizer for the same reason it is not feasible for the combustion turbine and auxiliary boiler. This source is even

smaller than the combustion turbine and auxiliary boiler, and it would be even more difficult, expensive, and uncertain to attempt implementation of the technology for these services.

7.1.4 Limited Operation

Continuous operation of the thermal oxidizer will be limited to firing of 13 MMBtu/hr of natural gas. Venting associated with start-up operations of the SRU will fire an additional 80 MMBtu/hr of natural gas, and be limited to 48 hours per year. This will limit the GHG emissions associated with this unit.

7.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

After eliminating the infeasible technologies for the thermal oxidizer, the remaining control options are:

- Use of lower-carbon fuel natural gas; and
- Limited operation.

7.3 STEP 5 – SELECTION OF GHG BACT FOR THE TAIL GAS THERMAL OXIDIZER

BACT for the tail gas thermal oxidizer is the use of the lower-carbon fuel, natural gas, and limiting the hours of start-up venting and the fuel burned during continuous operation. It is expected that the SJVAPCD permit will limit the criteria pollutant annual emissions, thus effectively limiting the annual usage of the thermal oxidizer. Compliance with these limits will be demonstrated by monitoring the fuel flow rate to the thermal oxidizer.

8. FLARES GHG BACT ANALYSIS

Although the Project is designed to avoid flaring during steady-state operations, flares are needed for safe operations in upset conditions and to protect the operators and equipment. The Project employs three pressure-relief systems and their corresponding flares (Gasification, Rectisol®, and SRU) for this purpose. All three flares are conventional pipe, elevated flares. Vessels, towers, heat exchangers, and other equipment are connected to piping systems that will discharge gases and vapors to a relief system in order to prevent excessive pressure from building up in the equipment, and to allow safe venting of gases during routine start-up, shut-down, or emergency upset events. During typical, non-start-up plant operation, the three flares will be operated in a standby mode with only minimal emissions from the natural-gas pilot flames. The flares will also be used occasionally to dispose of excess start-up and shut-down gases in a safe manner. Any time the flares are used, GHG emissions will be generated, although the total annual emissions from these flares are expected to be less than 2 percent of the facility total.

8.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

Potentially applicable GHG control technologies considered for the flares include:

- Minimization of amount and duration of flaring, preparation of a Flare Minimization Plan; and
- Flare gas recovery systems.

8.1.1 Minimization of Flaring

The principal method to minimize GHG emissions from the flares is to minimize the amount of material vented to the flares. As described above, the flares are used to safely dispose of gases containing VOCs and hazardous air pollutant constituents. Any time these gases are combusted in the flares, emissions of CO_2, CH_4, and N_2O are generated. Flare minimization is equally important to minimizing criteria pollutants, and has been incorporated into the base facility design and the original SJVAPCD permit. Based on the existing SJVAPCD permit, it is expected the revised SJVAPCD permit will limit flaring by limiting the annual volume of gas sent to each flare, and the durations of planned flaring events. Compliance with these conditions will be verified through non-resettable total flow meters for each flare. In addition to the fuel used for the pilot, each flare will be limited to the following planned operations:

- Gasification Flare: planned use limited to 70,536 MMBtu per year;
- SRU Flare: planned use limited to 36 MMBtu/hr of natural gas assist for 40 hours per year during start-ups and shut-downs;
- Rectisol® Flare: planned use limited to 430 MMBtu/hr of natural gas assist for 40 hours per year during start-ups and shut-downs.

HECA will prepare a Flare Minimization Plan that complies with SJVAPCD Rule 4311, and will contain technical specifications of each flare, including process flow diagrams, and a description of equipment, processes, or procedures that will be implemented to eliminate or minimize flaring. It

will also include an evaluation of preventive measures to reduce flaring that may be expected to occur during planned major maintenance activities, including start-up and shut-down, and an evaluation of these measures.

HECA plans two facility start-ups and shut-downs per year; emissions from the flares will be minimized by this limit. GHG emissions during start-up and shut-down are based on the amount of fuel flared; thus, minimizing the duration of these events will minimize the GHG emissions.

8.1.2 Flare Gas Recovery

HECA has also considered whether the use of a flare gas recovery compressor could be appropriate. Flare gas recovery has been implemented at some facilities that produce and use internally generated fuel gas streams such as petroleum refineries. However, flare gas recovery for the HECA facility is not feasible, for the following reasons.

First, unlike a refinery—which can and does need to operate sections of the plant while other sections are down for maintenance—HECA's planned maintenance will occur during an entire plant shut-down, while no gases are being produced. Flaring at the proposed HECA facility will be an infrequent occurrence, limited to breakdowns, malfunctions, and/or upsets. Planned flaring occurs during gasifier start-up and shut-down, which is estimated to occur for approximately 40 hours per year for the Rectisol® and SRU flares; and about 28 hours for the gasification flare.

Another significant difference is that refineries can recover some flare gas into their fuel gas cleanup system, which operates at less than 100 psig. In contrast, the HECA facility's analogous gas cleanup system, the AGR, operates at the much higher pressure of approximately 900 psig. This would significantly increase the equipment and operating costs of a flare gas recovery compressor, versus those at refineries. Further, during some of the flaring events, the flared material may not be suitable for routing to the AGR system, or the AGR system itself may be in the process of start-up, in an upset, or otherwise not ready to receive the gases.

Given the extremely infrequent nature of events producing flared gases available for recovery and the lack of a reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged not to be feasible for the HECA facility.

8.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

After eliminating the infeasible technologies for flares, the only remaining option for GHG control is minimization of amount and duration of flaring, and preparation of a Flare Minimization Plan.

8.3 STEP 5 – SELECTION OF GHG BACT FOR FLARES

BACT for GHG emissions from the HECA flares is minimization of the amount and duration of flaring. This will be accomplished through preparation of and adherence to a Flare Minimization Plan, as well as compliance with the permit conditions in the SJVAPCD permit, which serve to minimize the amount of material flared, and thus limit emissions of GHG and criteria pollutants.

9. NITRIC ACID UNIT GHG BACT ANALYSIS

The nitric acid plant is the largest source of GHGs within the Manufacturing Complex. N_2O emissions are a byproduct of the process stream in nitric acid production, and are considered "industrial process" emissions, resulting from ammonia oxidation.[12] There are several factors that affect N_2O formation, including combustion conditions in the oxidizing unit, catalyst, and burner design. The uncontrolled default N_2O emission factor used for nitric acid plants from the Intergovernmental Panel on Climate Change guidelines for U.S. facilities is 9 kilograms per metric ton (tonne) of nitric acid (HNO_3) produced (18 pounds N_2O per ton of HNO_3).[13] This value was used by USEPA in the development of the recent U.S. GHG inventory.[14]

9.1 STEPS 1 AND 2 – IDENTIFY POTENTIAL CONTROLS AND ASSESS FEASIBILITY

A review of the USEPA guidance document "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry" provided a description of the available controls for N_2O at nitric acid plants. These controls are distinguished by the location of the control measure within the nitric acid production process. Potentially applicable N_2O control technologies considered for the nitric acid unit include:

- Primary;
- Secondary; or
- Tertiary.

9.1.1 Primary Control

Primary control reduces the amount of N_2O formed in the ammonia oxidation step. This can be done by modifying the catalyst used in the oxidation process and/or modifying the operating conditions of this process. Primary controls are categorized as the suppression of N_2O formation, and include modifications to reactor design and catalysts; emission reduction is expected to be between 30 and 85 percent. Data from 14 European units with improved oxidation catalyst showed emissions in the range of 7.2 – 19.4 pounds N_2O per ton of HNO_3 (USEPA, 2010a).

9.1.2 Secondary Control

Secondary control reduces N_2O immediately after it is formed in the ammonia oxidation step. Secondary controls are categorized as catalytic decomposition of N_2O (to nitrogen [N_2] and O_2)

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[12] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Nitric Acid Production Industry*, USEPA, Office of Air and Radiation, December 2010.

[13] *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Industrial Processes and Product Use*. Intergovernmental Panel on Climate Change, ISBN 4-88788-032-4. http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol3.html.

[14] *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008*. EPA 430-R-10-006. Washington, D.C. April 15, 2010. http://epa.gov/climatechange/emissions/downloads10/508_Complete_GHG_1990_2008.pdf.

in the oxidation reactor, where they selectively remove N_2O. Reduction efficiencies for secondary controls range from 70 to 90 percent. USEPA reports that many secondary catalysts can achieve emission rates lower than 3 pounds of N_2O per ton of HNO_3 (USEPA, 2010a).

9.1.3 Tertiary Control

Tertiary control reduces N_2O by installation of a catalytic reactor either upstream or downstream of the tail-gas expansion unit following ammonia oxidation. Tertiary controls are categorized as catalytic reduction or catalytic decomposition in a catalytic reactor following the ammonia oxidation process.

Non-Selective Catalytic Reduction

An example of tertiary catalytic reduction is non-selective catalytic reduction (NSCR), which has the advantage of reducing both nitrogen oxides (criteria pollutant) and N_2O emissions. This type of control has a reduction efficiency of 80 to 95 percent. USEPA reports that 14 process trains in the U.S. use NSCR. These facilities have installed NSCR to control nitrogen oxides emissions; and as an additional benefit, NSCR reduces N_2O emissions. Only one U.S. plant with NSCR had emission test data which measured 0.43 pound N_2O per ton of HNO_3.

Catalytic Decomposition

Tertiary catalytic decomposition technology achieves the decomposition of N_2O to form N_2 and O_2 (as in secondary controls); but due to its placement following ammonia oxidation, it can achieve higher removal efficiencies for N_2O than the secondary control. In addition, this technology does not require any reducing agents or additives, and no undesirable by-products are formed. USEPA reports that most tertiary catalytic decomposition controls can achieve emission rates of less than 1.0 lb of N_2O per ton of HNO_3.

There is only one known N_2O BACT determination for a nitric acid plant in the U.S., for the U.S. Nitrogen facility in Green County, Tennessee, which proposed tertiary catalytic decomposition for control of N_2O. Although a GHG BACT determination was not required for the Southeast Idaho Energy project, because it received a Permit to Construct in November 2009, it included use of tertiary catalytic decomposition for N_2O reduction that controlled N_2O emissions to 3.4 pounds per of HNO_3.[15]

The N_2O emissions for the HECA nitric acid plant will be treated in a tertiary reduction system, based on its location at the end of the tail gas heat recovery system. Primary and secondary reduction occurs in the nitric acid unit equipment without any catalysis simply by the high process temperature. In the tertiary reduction, a reducing catalyst that uses high temperature rather than a reducing agent converts 95 percent of the remaining N_2O emission to N_2 and nitric oxide. The estimated HECA nitric acid plant uncontrolled emission rate is 6.32 pounds N_2O per ton of HNO_3. The oxidation catalyst is expected to achieve a 95 percent reduction in N_2O, resulting in a controlled emission rate of just 0.32 pound N_2O per ton HNO_3.

[15] *Air Quality Permit to Construct Number P-2009.0127*, Southeast Idaho Energy, LLC, American Falls, Idaho. Idaho Department of Environmental Quality, November 30, 2009.

9.2 STEPS 3 AND 4 – RANKING AND EVALUATION OF REMAINING CONTROLS

The most effective control technology is tertiary control. HECA proposes tertiary catalytic decomposition to reduce the N_2O emissions from the nitric acid unit by 95 percent, to a controlled emission rate of 0.32 pound N_2O per ton of HNO_3.

9.3 STEP 5 – SELECTION OF GHG BACT FOR NITRIC ACID UNIT

BACT is proposed to be use of tertiary catalytic decomposition to reduce the N_2O emissions from the nitric acid unit. HECA proposes tertiary catalytic decomposition to reduce the N_2O emissions from the nitric acid unit by 95 percent, to a controlled emission rate of 0.32 pound N_2O per ton of HNO_3.

This emission rate exceeds the average performance standard of the top 10 percent most efficient installations with tertiary controls (excluding units with NSCR) of 2.2 pounds N_2O per ton HNO_3, and is lower than 0.43 pound N_2O per ton of HNO_3 reported by the one nitric acid plant in the U.S. that uses NSCR.[13] Because of the low emission rate proposed by HECA, and the fact that the only previous nitric acid plant GHG BACT determination concluded that BACT was this same technology, the proposed BACT is believed to be the best control technology available, and no further analysis of control technologies is performed for the nitric acid plant. N_2O emissions from the nitric acid unit will be tested to demonstrate the BACT level.

The use of a tertiary reduction system, catalytic decomposition, to control N_2O emissions to 0.32 pound N_2O per ton of HNO_3, is considered to be BACT for N_2O for the nitric acid plant.

10. MANUFACTURING COMPLEX GHG BACT ANALYSIS

Although the nitric acid plant is the largest source of GHGs from the Manufacturing Complex, there are other small sources of GHG emissions, such as the urea absorber vents and the ammonia synthesis start-up heater. The BACT analysis for these sources is presented in this section.

Ammonia is the primary input for the majority of nitrogen-based fertilizer products, and is typically produced using either natural gas or petcoke, although the industry predominantly uses natural gas. Urea, ammonium nitrate, and UAN are all produced from ammonia. The International Fertilizer Industry Association found that in the production of ammonia, only 2.2 percent of the CO_2 from the fossil fuel feedstock is sold to users such as EOR or to the beverage industry; 33 percent is used for urea production; and the remainder is vented.[16] HECA will capture 90 percent of the carbon in the total syngas flow, 85 percent goes to EOR and sequestration, and the remainder is used in urea production; thus, the GHG emissions from the Manufacturing Complex are significantly lower than those for similar facilities.

10.1 UREA ABSORBER VENTS

The high- and low-pressure absorbers are used to scrub ammonia from the CO_2 feed gas. The only GHG emissions from the absorbers are minor amounts of CO_2. Emissions of CO_2 are restricted by good operating practices, in order to maintain the feed stream. CO_2 is a feed for the production of urea, and is therefore a valuable commodity.

The urea absorber vents' emissions of CO_2e are expected to be less than 120 tonnes per year. This is less than 0.02 percent of the HECA facility total. Due to the low level of CO_2 emissions, capture and recovery of the stream is not feasible. BACT for GHG is determined to be good operating practices.

CO_2 emissions from the urea absorber vents can be calculated from the amount of ammonia and CO_2 fed to the urea unit and the amount of urea produced: all quantities will be measured.

10.2 AMMONIA SYNTHESIS START-UP HEATER

Operation of the heater is expected to be intermittent, equivalent to only 140 hours at full-load operation, or approximately 7,700 MMBtu/yr. In addition, the heater will only combust a lower-carbon fuel, natural gas. GHG BACT for the heater is determined to be use of natural-gas fuel and restricted operating hours; these measures are also included in the criteria pollutant BACT for this unit. Due to the low use of this unit, add-on controls are not feasible. HECA proposes that the SJVAPCD permit conditions reflect this limited use, and that GHG BACT for this heater be determined to be limited usage. Compliance with this limit will be demonstrated by monitoring the natural gas flow rate to the heater.

[16] International Fertilizer Industry Association, Greenhouse gas emissions and fertilizer production, http://www.fertilizer.org/ifa/HomePage/SUSTAINABILITY/Climate-change/Emissions-from-production.html.

11. MISCELLANEOUS SOURCES GHG BACT ANALYSIS

The analyses for other small sources of GHG emissions, such as the emergency engines, fugitive emissions from equipment leaks, and circuit breakers, are included in this section.

11.1 EMERGENCY ENGINES

The HECA Project has three emergency engines: two diesel-fired 2,922 horsepower standby generators, and one diesel-fired 556 horsepower standby fire-water pump.

These emergency diesel engines will have the potential to emit GHGs (CO_2, CH_4, and N_2O) because they combust hydrocarbon fuel. However, because their use is limited to routine maintenance, inspection, and testing, their total annual emissions are very small. The use of diesel fuel is standard for emergency engines because it is the most reliable fuel for emergency scenarios when supplies of other fuels may be unavailable. For example, the use of electric engines or natural-gas–fired engines is not appropriate, because either energy source could be interrupted in certain emergency scenarios. Therefore, the only achievable approach to reducing GHGs from the emergency generator and fire-pump engines is to limit their use, and to use efficient engines. HECA proposes both measures.

HECA will use new engines meeting the latest efficiency and pollutant performance standards. Specifically, regarding criteria pollutants, these standby diesel-fired engines will meet the California Interim Tier 4 standards.

The standby fire-water pump engine will be limited to no more than 100 hours per year for reliability testing and maintenance purposes. The stand-by electric generators will each be limited to no more than 50 hours per year of operation. HECA proposes the SJVAPCD permit reflect this limited use, and that GHG BACT be defined as limited usage.

11.2 FUGITIVES

HECA estimates that there will be approximately 35 tons of CO_2e per year of emissions from Project equipment and pipe component leaks, such as pumps, valves, flanges, and compressors, after implementation of the leak detection and repair (LDAR) program. This emission estimate includes contributions from components in both CO_2 and CH_4 services, and will be less than 0.01 percent of total facility emissions.

Based on the existing SJVAPCD permit, it is expected that the revised SJVAPCD permit will require HECA to implement a Leak Inspection and Maintenance program for control of hazardous air pollutants, VOCs, and NH_3 on fugitive components in the Gasification Block, SRU, and Manufacturing Complex. These areas include streams that contain CO_2 and CH_4. The use of LDAR, although not specific for GHG emissions, has the secondary benefit of reducing GHG from these process units.

Because total fugitive emissions of CO_2e from equipment components are so small, relative to the overall facility emissions, further control of fugitive emissions would have minimal

additional benefit. The Project proposes the same LDAR program as outlined in the original SJVAPCD permit as BACT for fugitive emissions of GHG.

11.3 CIRCUIT BREAKERS

The facility's circuit breakers will have the potential to emit a very small amount of GHG, in the form of SF_6. Circuit breakers do not emit SF_6 directly, but they do have the potential for fugitive emissions (leaks). The HECA Project site will include a switchyard with approximately 8 circuit breakers, with a total SF_6 inventory of approximately 1,600 pounds (less than 1 tonne) of SF_6 in the enclosed-pressure breakers. SF_6 is a gaseous dielectric used in the breakers. It is a potent GHG with a "global warming potential" over a 100-year period 23,900 times greater than CO_2. Leakage is expected to be minimal. Even assuming a 0.5 percent annual leak rate, HECA estimates emissions equivalent to only 86 tonnes per year CO_2e. Nevertheless, this small source has been considered for purposes of this GHG BACT analysis.

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. The proposed alternative is to use state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. The best modern equipment can be guaranteed to leak at a rate of no more than 0.5 percent per year (by weight). This leak rate meets the current maximum leak rate standard established by the International Electrotechnical Commission. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10 percent of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively to prevent further release of the gas and maintain the insulation value in the circuit breakers. The use of enclosed-pressure SF_6 circuit breakers with leak detection is feasible for this location. HECA has proposed to use this equipment because of its performance benefits.

Another alternative is to substitute another, non-GHG substance for SF_6 as the dielectric material in the breakers. One alternative to SF_6 would be use of a dielectric oil or compressed air ("air blast") circuit breaker, which historically were used in high-voltage installations prior to the development of SF_6 breakers. This type of technology is feasible, although SF_6 has become the predominant insulator and arc-quenching substance in circuit breakers today because of its superior capabilities. Additionally, this type of circuit breaker would require significantly larger equipment to replicate the same insulating and arc-quenching capabilities of the SF_6 breakers. The larger oil/air-blast breakers would require that additional land be devoted to the Project, would generate additional noise, and would increase the risks of accidental releases of dielectric fluid and/or associated fires.

Although oil/air-blast breakers are theoretically feasible, they are not preferred versus the choice of SF_6 breakers because of their negative characteristics and the fact that the use of the latest SF_6 breakers only results in very small GHG emissions. This conclusion is supported by the most recent report released by the USEPA SF_6 Partnership, which states: "[n]o clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear,

due to its inertness and dielectric properties."[17] Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc-quenching properties in high-voltage applications.[18] Although some progress has reportedly been made in medium- or low-voltage applications, most studies have concluded "that there is no replacement gas immediately available to use as an SF_6 substitute"[19] for high-voltage applications.

Based on this analysis, HECA concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT option.

[17] SF6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, December 2008, p. 1 (available at www.epa.gov/electricpower-sf6).

[18] See, e.g., Christophorou, L.G., J.K. Olthoff and D.S. Green, National Institute of Standards and Technology (NIST), Electricity Division (Electronics and Electrical Engineering Laboratory) and Process Measurements Division (Chemical Science and Technology Laboratory), NIST Technical Note 1425: Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6, November 1997 (hereinafter, "NIST Technical Note 142"); available at: http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf; see also U.S. Climate Change Technology Program, Technology Options for the Near and Long Term, November 2003, § 4.3.5, "Electric Power System and Magnesium: Substitutes for SF6," at 185; available at: http://www.climatetechnology.gov/library/2003/tech-options/tech-options-4-3-5.pdf.

[19] T. Olsen (Manager, Siemens Power Transmission & Distribution), Siemens Electrical Distribution Products Catalog 2006, "Medium Voltage Equipment: Special Applications & Technical Information," at 13-29 (summarizing the results of the NIST study referenced in the preceding footnote); available at: http://www.sea.siemens.com/SpeedFax06/Speedfax06files/06Speedfaxpdfs/06Speedfax_13/13_28-29.pdf.

12. BACT DETERMINATION SUMMARY

Table 12-1 summarizes the BACT proposed as a result of this GHG BACT analysis. The table also notes key relevant SJVAPCD permit conditions, updated from the December 2010 permit to reflect the modified Project design, which also serve to restrict facility operation and limit GHG emissions. It is expected that the new SJVAPCD permit and conditions will be similar to those determined in December 2010.

The HECA Project was designed to minimize GHG emissions. This is done primarily through the capture of 90 percent of the carbon in the raw syngas in a high-purity CO_2 stream for use in EOR and subsequent sequestration. This ensures that a low-carbon fuel is used as the basis for generation of nitrogen-based products and electric power. The CO_2-power-related emissions would be less than or equal to 400 lb/MWh, compared with the SB 1368 emission performance standard of 1,100 lb/MWh. Also, many additional design features have been implemented that conserve and reuse thermal energy, and in so doing, reduce GHG emissions from the HECA Project.

Table 12-1
Summary of Proposed GHG BACT Permit Limits for HECA

Source Type	BACT Determination	Proposed GHG-Specific BACT Limit	Relevant SJVAPCD Permit Limits
HECA Project (entire facility)	Energy-efficient facility design, plus controls listed below.	535,278 tonnes of CO_2e per year	No equivalent SJVAPCD Permit Limit
Combustion Turbine/ HRSG	Hydrogen-rich fuel Firing: Pre-combustion capture of CO_2 Natural Gas Backup: Limited Operation.	Capture 90 percent of carbon in syngas (as monitored through CO_2 content in hydrogen-rich fuel and captured CO_2 stream). CO_2 power related emissions to less than or equal to 400 lb/MWh (based on SB 1368).	Fire only hydrogen-rich fuel and PSA off-gas, and natural gas as backup fuel. Hourly, daily, and annual limits on NO_X, VOC, CO, PM_{10}, SO_X. Monitor fuel consumption.
CO_2 Recovery System and Vent	Compression and Transport CO_2 to EOR Good Operating Practices Limited Operation	No additional limits required beyond air permit.	Venting only when compression, transportation, or injection system is unavailable and during gasifier start-up and shut-down. Flow measurement. Concentration, hourly, and annual limits on CO, VOC, H_2S and COS
Auxiliary Boiler	Use of gas fuels, Energy-Efficient Design, process heat integration, Limited Operation, Periodic Tuning	Boiler tuning and limits from air permit.	Fire only natural gas. Total annual heat input limited to 466 billion Btu and monitor fuel use.
Thermal Oxidizer	Good Operating Practices	No additional limits required beyond air permit.	Annual operating limits.
Gasification, SRU, and Rectisol® Flares	Good Operating Practices, Flare Minimization Plans, Limited Operation	No additional limits required beyond air permit.	Flare Minimization Plan, Total flow monitors, Annual operating limits.

Table 12-1
Summary of Proposed BACT Permit Limits for GHG (Continued)

Source Type	BACT Determination	Proposed GHG-Specific BACT Limit	Relevant SJVAPCD Permit Limits
Nitric Acid Unit	Tertiary Control (Catalytic Decomposition)	N_2O emissions of 0.32 pound N_2O per ton HNO_3 based on an annual average demonstrated with testing.	Annual operating limits.
Ammonia Synthesis Plant Start-up Heater	Good Operating Practices, Natural Gas Fuel, Limited Operation	No additional limits required beyond air permit.	Fire only natural gas. Total annual heat input limited to 7,700 MMBtu and monitor fuel use.
Urea Absorber Vents	Good Operating Practices	No additional limits required beyond air permit.	Annual operating limits.
Equipment Fugitive Leaks	No further controls	No additional limits required beyond air permit.	LDAR on select process areas
Emergency Engines	Good Operating Practices	No additional limits required beyond air permit.	50 hours non-emergency operation per year for electric generators; 100 hours non-emergency operation per year for firewater pump
Circuit Breakers	Enclosed pressure SF_6 circuit breakers with leak detection	Use of enclosed pressure SF_6 circuit breakers with leak detection.	No SJVAPCD Permit Limits

Notes:

BACT = Best Available Control Technology
Btu = British thermal unit
CO = carbon monoxide
CO_2 = carbon dioxide
CO_2e = carbon dioxide equivalents
COS = carbonyl sulfide
EOR = enhanced oil recovery
GHG = greenhouse gas
H_2S = hydrogen sulfide
HECA = Hydrogen Energy California LLC
HNO_3 = nitric acid
HRSG = heat recovery steam generator
Lb/MWh = pound per megawatt hour
LDAR = leak detection and repair
MMBtu = million British thermal units
NO_X = nitrogen oxides
PM_{10} particulate matter less than or equal to 10 microns in diameter
PSA = Pressure Swing Adsorption
SB = Senate Bill
SF_6 = sulfur hexafluoride
SJVAPCD = San Joaquin Valley Air Pollution Control District
SO_X = sulfur oxides
SRU = sulfur recovery unit
VOC = volatile organic compound

13. REFERENCES

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Appendix D

Operational Criteria Pollutant Emissions

HECA Total Combined Annual Criteria Pollutant Emissions

Equipment \ Pollutant	NO_X	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$
	tons/year					
HRSG/CTG (1)	109.7	92.9	15.3	17.2	54.6	54.6
Coal Dryer(1)	17.4	13.3	2.4	2.8	5.6	5.6
Auxiliary Boiler	1.4	8.6	0.9	0.5	1.2	1.2
Tail Gas Thermal Oxidizer	13.4	11.2	0.3	8.3	0.4	0.4
CO_2 Vent		124.1	2.8			
Gasification Flare	3.2	18.5	0.01	0.02	0.03	0.03
Rectisol Flare	1.2	0.8	0.01	0.3	0.03	0.03
SRU Flare	0.2	0.2	0.003	0.4	0.006	0.006
Cooling Towers (2)					25.5	15.3
Emergency Generators(3)	0.2	0.8	0.1	0.001	0.02	0.02
Fire Water Pump	0.09	0.2	0.01	0.0003	0.001	0.001
Nitric Acid Unit	17					
Urea Pastillation Unit					0.2	0.2
Ammonium Nitrate Unit					0.8	0.8
Ammonia Startup Heater	0.04	0.14	0.02	0.01	0.02	0.02
Material Handling (4)					1.9	1.9
Fugitives		4.6	13.4			
Total Annual	**163.7**	**275.2**	**35.4**	**29.5**	**90.3**	**80.2**

Source: HECA Project

Notes:

(1) Total annual HRSG and Coal Dryer emissions represent the maximum annual emissions during normal operations plus startup and shutdown emissions

(2) Includes contributions from all three cooling towers

(3) Includes contributions from both emergency generators

(4) Material handling emissions are shown as the contribution of all dust collection points.

CO = carbon monoxide

HRSG=Heat Recovery Steam Generator

CTG = combustion turbine generator

NO_X = nitrogen oxides

PM_{10}= particulate matter less than 10 microns in diameter

$PM_{2.5}$ =particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})

SO_2 = sulfur dioxide

VOCs = volatile organic compounds

4/24/2012

Basis: MHI GT - Model: M501GAC

With PSA Off-gas and H2-rich Gas Duct Firing

Maximum Emissions based on Case 1 - On-peak with duct-firing at 97F ambient

CGT Max Fuel Input =	2583	x 10^6 Btu/hr (HHV) of syngas
Duct Firing Max Fuel Input =	278	x 10^6 Btu/hr (HHV) of PSA Off-gas and H2-rich syngas
HRSG stack gas =	255,463	lbmol/hr, dry, corrected to 15% O2

Total HRSG Flue Gas Emission Rates with Duct Firing of PSA Off-gas and H2-rich syngas

	Emission Factors lb/10^6 Btu (HHV)	Basis
NOx	0.011	2.5 ppmc
CO	0.008	3 ppmc
VOC	0.0015	1 ppmc
$PM_{10}/PM_{2.5}$	0.008	filterable (front-half) + condensible (back half)
SO2**	0.0002	2 ppmv total sulfur in syngas, 10 ppmv sulfur in PSA Off-gas
NH3		5 ppmc ammonia slip

Notes: Emission Factors are based on the maximum emissions from all of the cases examined (On-peak and Off-peak)
ppmc denotes ppm by volume, dry, corrected to 15% O2
** Maximum SO2 emission occurs for OFF-peak, 97 deg F (Case 2)

Maximum short-term emissions from HRSG stack, normal operations on peak

HRSG Emissions	lb/hr	Basis
NOx	25.0	Case 1 (ON Peak, 97 deg Ambient)
CO	18.3	Case 1 (ON Peak, 97 deg Ambient)
VOC	3.5	Case 1 (ON Peak, 97 deg Ambient)
$PM_{10}/PM_{2.5}$	12.9	Case 3 (ON Peak, 39 deg Ambient)
SO2**	4.1	Case 2 (OFF Peak, 97 deg Ambient)
NH3	18.5	Case 1 (ON Peak, 97 deg Ambient)

	Exhaust gas (lbmol/hr)	Exit velocity (m/s)	Exhaust flow (ft3/sec)	Exit velocity (ft/sec)
min HRSG fluegas to HRSG stack during ON peak (Case 1) =	167,092	16.40	22,356.58	53.81
Min HRSG fluegas to HRSG stack during OFF Peak (Case 2) =	126,704	12.44	16,952.70	40.80
HRSG fluegas to HRSG stack during ON Peak (Case 3) =	176,804	17.35	23,655.98	56.94

Annual average emissions from HRSG Stack

Basis: Case 5 (ON Peak, Avg. Ambient)

HRSG Emissions	lb/hr
NOx	24.9
CO	18.2
VOC	3.5
$PM_{10}/PM_{2.5}$	12.8
SO2*	4.1
NH3	18.4

	Exhaust gas (lbmol/hr)	Exit velocity (m/s)
HRSG fluegas to HRSG stack (Case 5) =	171,498	16.83

Maximum short-term emissions from coal dryer stack

Coal Dryer Emissions	lb/hr	Basis
NOx	4.4	Case 1 (ON Peak, 97 deg Ambient)
CO	3.2	Case 1 (ON Peak, 97 deg Ambient)
VOC	0.6	Case 1 (ON Peak, 97 deg Ambient)
$PM_{10}/PM_{2.5}$	1.4	Case 3 (ON Peak, 39 deg Ambient)
SO2	0.9	Case 2 (OFF Peak, 97 deg Ambient)
NH3	3.2	Case 1 (ON Peak, 97 deg Ambient)

*Baghouse PM control to 0.001 gr/dscf

	Exhaust gas (lbmol/hr)	Exit velocity (m/s)
Min HRSG fluegas to coal dryer (Case 4) =	28,788	5.84

Note: Coal dryer emission rates are relatively constant for both On- and OFF-peak operation.

Annual average emissions from coal dryer stack

Basis: Case 5 (ON Peak, Avg. Ambient)

Coal Dryer Emissions	lb/hr
NOx	4.2
CO	3.1
VOC	0.6
$PM_{10}/PM_{2.5}$	1.4
SO2	0.7
NH3	3.1

*Baghouse PM control to 0.001 gr/dscf

	Exhaust gas (lbmol/hr)	Exit velocity (m/s)
HRSG fluegas to coal dryer (Case 5) =	29,102	5.90

Startup/Shutdown - HRSG Stack & Coal Drying Stack

Information provided by MHI

Expected Emissions vs. CTG Load (Natural Gas)				
	CTG load			
	80%	40%	20%	units
NOx	42	25	18	ppmc
CO	130	2900	5000	ppmc
VOC	1.1	9	50	ppmc
$PM_{10}/PM_{2.5}$	15	15	15	lb/hr
SOx*	0.4	0.4	0.4	ppmc

* 0.4 ppmc SO2 in fluegas corresponds to about 12.6 ppmv total sulfur in natural gas fuel.

Expected Emissions vs. CTG Load (Syngas)		
	CTG load	
	40%	units
NOx	19	ppmc
CO	39	ppmc
VOC	2	ppmc
$PM_{10}/PM_{2.5}$	13	lb/hr
SOx	2	ppmvw

Compound	lb/lbmol
NO2	46.01
CO	28.01
VOC	16.04
SO2	64.06
NH3	17.03

HRSG/Coal Drying Total Exhaust Flow Basis								
Load/Fuel	80% on NG		40% on NG		20% on NG		40% on Syngas	
O2 mol% (wet)	11.41%		14.15%		15.22%		11.74%	
H2O mol% (wet)	14.10%		10.63%		9.28%		10.50%	
MW	27.79	lb/lbmol	28.05	lb/lbmol	28.16	lb/lbmol	27.66	lb/lbmol
HRSG flue gas*	167,600	lbmol/hr	138,400	lbmol/hr	127,400	lbmol/hr	140,200	lbmol/hr
NOx Stack Conc (assumed)	4	ppmc	25	ppmc	18	ppmc	10	ppmc
CO Stack Conc (assumed)	5	ppmc	400	ppmc	1000	ppmc	20	ppmc
VOC Stack Conc (assumed)	2	ppmc	9	ppmc	50	ppmc	2	ppmc
NH3 slip	5	ppmc	0		0		5	ppmc
Turbine Fuel Flow							14,218	lbmol/hr
HRSG flue gas (wet)	4,657,604	lb/hr	3,882,120	lb/hr	3,587,584	lb/hr	3,877,932	lb/hr
HRSG flue gas (dry, corrected to 15% O2)	185,516	lbmol/hr	106,371	lbmol/hr	81,062	lbmol/hr	165,183	lbmol/hr
Duct Burner Gas HHV							85	MMBtu/hr
Coal Drying Flow (wet)			480,180	lb/hr			480,180	lb/hr

*Includes gas routed to coal dryer.

HRSG Startup													
Step	Duration (hrs)		SO2	NOx	CO	$PM_{10}/PM_{2.5}$	VOC	NH3	Description	Flow (lbmol/hr)	Exhaust flow (ft3/sec)	Exit velocity (ft/sec)	Exit velocity (m/s)
1. 20% on NG	0.5	lb/hr	2.1	67.1	2270	15.0	65	0	CTG ignition and synchronization	127,400	17,045.88	41.03	12.51
		lb	1.0	33.6	1135	7.5	32.4	0.0					
2. 40% on NG	2	lb/hr	2.4	107.2	1044	13.1	13	0	HRSG/STG Warm-up, Ramp CTG to 40%	121,300	16,229.71	39.06	11.91
		lb	4.8	214	2088	26.3	26.8	0.0					
3. 40% on Syngas	50	lb/hr	2.4	66.6	81	13	4.6	0.0	CTG fuel change over, Start up PSA/Ammonia/Urea Plant	123,100	16,470.54	39.64	12.08
		lb	120	3329	4052	657	232	0.0					
Tons/Startup			**0.06**	**1.79**	**3.64**	**0.35**	**0.15**	**0.00**					

*Coal drying starts at step 2 above.

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Coal Drying Startup													
Step	Duration (hrs)		SO2	NOx	CO	$PM_{10}/PM_{2.5}$	VOC	NH3	Description	Flow (lbmol/hr)	Exhaust flow (ft3/sec)	Exit velocity (ft/sec)	Exit velocity (m/s)
2. 40% on NG	2	lb/hr	0.3	15.1	147.4	0.9	1.9	0.0	Gasifier fuel changeover	17,100	2,287.95	11.38	3.47
		lb	0.7	30.3	294.7	1.9	3.8	0.0					
3. 40% on Syngas	50	lb/hr	0.3	9.4	11.5	0.9	0.7	0.0	GTG fuel change over, Start up PSA/Ammonia/Urea Plant	17,400	2,328.09	11.58	3.53
		lb	16.9	470	573	47	33	0.0					
Tons/Startup			**0.01**	**0.25**	**0.43**	**0.02**	**0.02**	**0.00**					

*PM emission rate based on 0.001 grain/dscf

HRSG Shutdown													
Step	Duration (hrs)		SO2	NOx	CO	$PM_{10}/PM_{2.5}$	VOC	NH3	Description	Flow (lbmol/hr)	Exhaust flow (ft3/sec)	Exit velocity (ft/sec)	Exit velocity (m/s)
1. 40% on Syngas	4	lb/hr	2.4	66.6	81.0	13	4.6	0.0	PSA, Ammonia and Urea plant shutdown, Gasifier to 60%, CTG to 40%	123,100	16,470.54	39.64	12.08
		lb	9.6	266	324	52.6	18.5	0.0					
2. 40% on NG	3	lb/hr	2.7	122	1191	15.0	15.3	0.0	CTG fuel change over, Gasifier depressurization	138,400	18,517.65	44.57	13.58
		lb	8.2	367	3574	45.0	45.9	0.0					
3. 20% on NG	2	lb/hr	2.1	67.1	2270	15.0	64.8	0.0	Minimum plant load on NG	127,400	17,045.88	41.03	12.51
		lb	4.2	134	4539	30.0	129.7	0.0					
Tons/Shutdown			**0.01**	**0.38**	**4.22**	**0.06**	**0.10**	**0.00**					

Coal Drying Shutdown													
Step	Duration (hrs)		SO2	NOx	CO	$PM_{10}/PM_{2.5}$	VOC	NH3	Description	Flow (lbmol/hr)	Exhaust flow (ft3/sec)	Exit velocity (ft/sec)	Exit velocity (m/s)
1. 40% on Syngas	4	lb/hr	0.3	9.4	11.5	0.9	0.7	0.0	PSA, Ammonia and Urea plant shutdown, Gasifier to 60%, CTG to 40%	17,400	2,328.09	11.58	3.53
		lb	1.4	37.6	45.8	3.8	2.6	0.0					
Tons/Startup			**0.00**	**0.02**	**0.02**	**0.00**	**0.00**	**0.00**					

*PM emission rate based on 0.001 grain/dscf

CTG steady state operation at 80% load on natural gas for 2 weeks per year

HRSG Emissions - Natural Gas Operations													
Step	Duration (hrs)		SO2	NOx (4 ppmc)	CO (5 ppmc)	$PM_{10}/PM_{2.5}$	VOC (2 ppmc)	NH3 (5 ppmc)	Description	Flow (lbmol/hr)	Exhaust flow (ft3/sec)	Exit velocity (ft/sec)	Exit velocity (m/s)
1. 80% on NG	336	lb/hr	4.7	34.1	26.0	15.0	5.9	15.8	CTG operation at 80% load on NG	150,700	20,163.37	48.53	14.79
		lb	1596	11469	8727	5040	1995	5298					
Tons/yr			**0.80**	**5.73**	**4.36**	**2.52**	**1.00**	**2.65**					
Natural gas heat input (HHV)	2400	Emission Factors lb/MMBtu (HHV)	0.002	0.015	0.011	0.007	0.003	0.007					

Heat Input = 2167x10^6 Btu/hr, LHV (approx 2400x10^6 btu/hr, HHV)

HRSG & Coal Dryer Maximum Annual Operation Emissions

	HRSG, ton/yr				Gasifier Coal Dryer, ton/yr		
	SU & SD	**Normal Op**	**Nat Gas BU**	**Total**	**SU & SD**	**Normal Op**	**Total**
NOx	4.34	99.6	5.73	109.7	0.54	16.9	17.4
CO	15.7	72.8	4.36	92.9	0.91	12.4	13.3
VOC	0.49	13.9	1.00	15.3	0.04	2.4	2.4
$PM_{10}/PM_{2.5}$	0.82	51.3	2.52	54.6	0.05	5.6	5.6
SO2*	0.147	16.3	0.80	17.2	0.02	2.8	2.8
NH3	0.00	73.6	2.65	76.3	0.00	12.5	12.5

Maximum Annual Operation:

SU & SD	2	per year
Normal op	8000	hr/yr
Nat gas op	336	hr/yr

Annualized Startup/Shut down Emission rate for NO2 1-hr NAAQS				
Source	**HRSG**		**Coal Dryer**	
Emission Scenario	Startup, Shutdown, Natural Gas	Normal On-peak (Case 1)	Startup, Shutdown	Normal On-peak (Case 1)
Emission rate (lb/hr)	2.30	25.01	0.12	4.4

Normal operations are higher, therefore normal operating emissions used in NAAQS modeling

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CALCULATIONS FOR COMBINED CYCLE EMISSIONS

Basis: MHI Data for 501GAC, 1 on 1 with O2 Blown Gasifier (Lee Ranch Coal 75cal%/ Carson High Sulfur Coke 25cal%)

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Ambient temp, deg F	97	97	39	39	65	65
ON Peak/OFF Peak	ON	OFF	ON	OFF	ON	OFF
HRSG Flue Gas Split to Coal Dryer						
Flue gas to coal dryer, lbmol/hr (wet)	29,208	28,996	28,996	28,788	29,102	28,996
Flue gas to HRSG stack, lbmol/hr (w)	167,092	126,704	176,804	142,412	171,498	135,904
Coal Dryer Stack Emissions						
NOx, lb/hr	4.4	4.3	4.1	3.8	4.2	4.0
CO, lb/hr	3.2	3.1	3.0	2.8	3.1	2.9
VOC, lb/hr	0.61	0.59	0.57	0.52	0.59	0.55
Particulate, lb/hr (3)	1.4	1.4	1.4	1.4	1.4	1.4
SO2, lb/hr	0.7	0.9	0.7	0.8	0.7	0.8
NH3, lb/hr	3.23	3.16	3.0	2.8	3.1	2.9
HRSG Stack Emissions						
NOx, lb/hr	25.01	18.7	24.96	18.7	24.9	18.6
CO, lb/hr	18.3	13.6	18.2	13.6	18.2	13.6
VOC, lb/hr	3.48	2.60	3.47	2.59	3.47	2.59
Particulate, lb/hr	12.77	12.21	12.89	12.48	12.82	12.36
SO2, lb/hr	4.06	4.09	4.09	4.03	4.07	3.98
NH3, lb/hr	18.5	13.8	18.4	13.8	18.4	13.8

Notes:
(1) "ppmc" denotes parts per million by volume, dry, corrected to 15% O2
(2) Sulfur in the PSA Off-gas is based on the total sulfur quantity in the feed to the PSA
(3) PM emission from coal dryer based on stack baghouse outlet dust loading of 0.001 grain/dscf.

AUXILIARY BOILER — Emissions Summary

4/17/2012

Description

Mainly used for startups, could be used for other purposes, primarily during power block outages.

Maximum steam generation	150,000	lb/hr
Maximum heat release	213	10^6 Btu/hr, HHV
Natural gas fuel, only		

Emission factors		
	lb/10^6 Btu, HHV	**Basis**
SO2	0.00204	12.65 ppmv total sulfur in pipeline natural gas (max short-term)
NOx	0.006	Low NOx burner and SCR, 5 ppmvd (3% O2)
CO	0.037	50 ppmvd (3% O2)
$PM_{10}/PM_{2.5}$	0.005	Similar equipment from previous project
VOC	0.004	Similar equipment from previous project
NH3	0.0022	5 ppmvd (3% O2) NH3 slip

Emissions		
	Max short-term lb/hr (1)	**Annual average ton/yr (2)**
SO2	0.4	0.48
NOx	1.3	1.4
CO	7.9	8.6
$PM_{10}/PM_{2.5}$	1.07	1.17
VOC	0.85	0.93
NH3	0.47	0.51

Notes:

(1) Maximum 1-hr, 3-hr, 8-hr, and 24-hr average emission rates.

(2) Maximum annual capacity factor of 25% (i.e., annual fuel consumption less than 0.25 x 8760 hr/yr x 213 million Btu/hr = 466 billion Btu/yr)

4/17/2012

Description

The Tail Gas Thermal Oxidizer (TGTO) is primarily intended to safely dispose of SRU tail gas in the event of an emergency or upset. The TGTO will also be be used to dispose of waste gas during SRU startups and to futher dispose of miscellaneous vent streams from the gasification area. These vent streams may contain trace amounts of reduced sulfur compounds and/or ammonia that could cause nuisance odors if vented directly to the atmosphere.

Process Vent Disposal

Assume nominal natural gas fuel consumption = 13 million Btu/hr

Assume an allowance of 2 lb/hr SO2 emission to account for sulfur in the various vent streams plus fuel.

Emission Calculations

NOx =	0.24	lb/10^6 Btu, HHV (based on previous project, 54 ppmvd @ 3% O2)
=	3.1	lb/hr
CO =	0.2	lb/10^6 Btu, HHV (based on previous project, 74 ppmvd @ 3% O2)
=	2.6	lbhr
SO2 =	2	lb/hr
VOC =	0.006	lb/10^6 Btu, HHV (AP-42, Table1.4 -2)
=	0.1	lb/hr
$PM_{10}/PM_{2.5}$ =	0.008	lb/10^6 Btu, HHV (AP-42, Table1.4 -2)
=	0.1	lb/hr

SRU startup natural gas combustion products disposal

Waste gas

Natural gas fuel 80 x 10^6 Btu/hr, HHV

Emission Calculations

(emission factors same as above)

NOx =	0.24	lb/10^6 Btu, HHV
=	19.2	lbhr
CO =	0.2	lb/10^6 Btu, HHV
=	16.0	lbhr
SO2 =	0.00204	lb/10^6 Btu, HHV
=	0.16	lbhr
VOC =	0.006	lb/10^6 Btu, HHV
=	0.48	lbhr
$PM_{10}/PM_{2.5}$ =	0.008	lb/10^6 Btu, HHV
=	0.64	lbhr

Maximum Short-term Emission Rates

	lb/hr
NOx	22.3
CO	18.6
SO2	2.2
VOC	0.6
$PM_{10}/PM_{2.5}$	0.7

Annualized Startup Emission rate for NO2 1-hr NAAQS

lb/hr

0.1223

Normal operations are higher, therefore normal operating emissions used in NAAQS modeling

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Annual Emission Calculations

Assumed annual operating scenario

TGTO normal operation for disposing miscellaneous vent gas

8314 hr/yr

NOx =	13.0	ton/yr
CO =	10.8	ton/yr
SO2 =	8.3	ton/yr
VOC =	0.32	ton/yr
$PM_{10}/PM_{2.5}$ =	0.43	ton/yr

SRU startup hrs/yr = 48 (approx 2 events @ 80 x 10^6 Btu/hr)

NOx =	0.461	ton/yr
CO =	0.3840	ton/yr
SO2 =	0.0039	ton/yr
VOC =	0.0115	ton/yr
$PM_{10}/PM_{2.5}$ =	0.0154	ton/yr

Total annual emission

NOx =	13.43	ton/yr
CO =	11.19	ton/yr
SO2 =	8.32	ton/yr
VOC =	0.34	ton/yr
$PM_{10}/PM_{2.5}$ =	0.45	ton/yr

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CO2 Vent Maximum Operations

Short-term Emission Rates

Total flow =	761,400	lb/hr	*Based on 380.7 stph CO2 to pipeline from
=	17,584	lbmol/hr	Plant Performance Study
H2S =	10	ppmv	
=	6.0	lb/hr	
COS =	10	ppmv	
	10.6	lb/hr	
CO =	1000	ppmv	(ranges from 500 to 1000 ppmv)
=	492	lb/hr	
VOC (MeOH) =	40	ppmv	
	11	lb/hr (as CH4)	

Annual Emissions

Assume	21	days/yr CO2 venting at full rate
	10	ppmv COS, annual average concentration
H2S =	1.5	ton/yr (based on 10 ppmv)
COS =	2.7	ton/yr (as COS, based on 10 ppmv)
CO =	124	ton/yr (based on 1000 ppmv)
VOC =	2.8	ton/yr (as CH4, based on 40 ppmv)

Note: These emissions represent the maximum emissions associated with Infrequent venting of product CO2.

Emission factors

	lb/10^6 Btu, HHV	Basis
Normal Operation (each flare) - pilots only, natural gas fuel		
SO2	0.00204	12.65 ppmv total sulfur in pipeline natural gas
NOx	0.12	Supplier data
CO	0.08	Supplier data
$PM_{10}/PM_{2.5}$	0.003	Supplier data
VOC	0.0013	99% VOC destruction for typical natural gas
Gasifier Startup - waste gases or H2-rich gas to Gasification Flare		
SO2	negligible	Startup - no sulfur in startup feed
NOx	0.07	Supplier data
CO (1)	2	Supplier data (98% destruction of CO in waste gas)
CO (2)	0.37	Supplier data
$PM_{10}/PM_{2.5}$	negligible	Supplier data
VOC	negligible	no VOC in waste gas or H2-rich gas

(1) Unshifted syngas
(2) Shifted syngas

Short-term Emission Calculations
Normal Operation - include pilots only, natural gas fuel
Maximum emissions include max of startup or shutdown plus pilot

Gasification Flare pilot fuel = 0.5 x 10^6 Btu/hr
SRU and Rectisol Flares pilot fuel = 0.3 x 10^6 Btu/hr, each

	Pilot	Max hourly emissions	Max daily emissions
	lb/hr	lb/hr	lb/hr
Gasification Flare			
SO2	0.00102	6.0	0.2
NOx	0.06	351.2	35.7
CO	0.04	4772.0	283.0
$PM_{10}/PM_{2.5}$	0.0015	8.8	0.4
VOC	0.0007	3.8	0.2
SRU Flare			
SO2	0.0006	18.4	18.4
NOx	0.036	7.9	7.9
CO	0.0240	2.9	2.9
$PM_{10}/PM_{2.5}$	0.0009	0.1	0.1
VOC	0.0004	0.05	0.05
Rectisol Flare			
SO2	0.0006	15.0	15.0
NOx	0.036	51.6	51.6
CO	0.0240	34.4	34.4
$PM_{10}/PM_{2.5}$	0.0009	1.3	1.3
VOC	0.0004	0.6	0.6

Startup/Shutdown - Gasification Flare

*Based on Startup/Shutdown Procedures provided by MHI for the PurGen One Project

Startup								
Step	Duration (hrs)	Heat Input (mmbtu/hr)		SO2	Nox	CO	$PM_{10}/PM_{2.5}$	VOC
2. Flaring NG	3	2,926	lb/hr	6.0	351.2	234.1	8.8	3.8
			lb	17.9	1053.5	702.3	26.3	11.4
3. Flaring Unshifted Syngas	2	2,386	lb/hr	0.0	167.0	4772.0	0.0	0.0
			lb	0.0	334.0	9544.0	0.0	0.0
4. Flaring Shifted Syngas	5	2,413	lb/hr	0.0	168.9	892.8	0.0	0.0
			lb	0.0	844.6	4464.1	0.0	0.0
Tons/Startup				**0.01**	**1.12**	**7.36**	**0.01**	**0.01**

Shutdown								
Step	hrs	mmbtu/hr		SO2	Nox	CO	$PM_{10}/PM_{2.5}$	VOC
1. Flaring Shifted Syngas	4	2,413	lb/hr	0	169	893	0	0
			lb	0	676	3,571	0	0
Tons/Shutdown				**0.00**	**0.34**	**1.79**	**0.00**	**0.00**

Gasification Flare

Pilot gas = 4380 x 10^6 Btu

2 startups/shutdowns per year

Gasification Flare Annual Emissions

	ton/yr		
	S/U and S/D	**Pilot**	**Total**
SO2	0.02	0.004	0.022
NOx	2.91	0.263	3.170
CO	18.28	0.175	18.457
$PM_{10}/PM_{2.5}$	0.026	0.007	0.033
VOC	0.01	0.003	0.014

Annualized Startup/Shut down Emission rate for NO2 1-hr NAAQS

lb/hr

0.66

Startup/Shutdown Operation - SRU Flare

Acid gas vent to elevated flare prior to introducng to SRU

Acid gas = 4600 lb/hr SO2 = 72 lbmol/hr H2S

Assume 99.6% sulfur removal for caustic scrubber:

Scrubbed acid gas = 18.4 lb/hr SO2

plus approx 25,000 to 140,000 scf/hr of mostly CO2 and other inerts

Assume 36 x10^6 Btu/hr of natural gas assist fuel

added to scrubbed acid gas for flaring.

Approximate heating value of mixed gas to flare

= 36 x10^6 Btu /(140,000 + 36,000) scf

= 205 Btu/scf, adequate for combustion

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Estimated Startup SRU Flare Emissions - flaring scrubbed acid gas

	lb/hr
SO2	18.4
NOx	4.3
CO	2.9
$PM_{10}/PM_{2.5}$	0.11
VOC	0.05

99.6% effective caustic scrubber

(Emissions for NOX, CO, PM10, and VOC based on factors for natural gas pilots above)

SRU Flare

SRU startup vent gas to flare 1) = 40 hr /yr*

Pilot gas = 2628 x 10^6 Btu

SRU Flare Annual Emissions

	ton/yr		
	S/U and S/D	Pilot	Total
SO2	0.368	0.003	0.371
NOx	0.086	0.16	0.24
CO	0.058	0.11	0.16
$PM_{10}/PM_{2.5}$	0.002	0.004	0.006
VOC	0.001	0.002	0.003

Annualized Startup/Shut down Emission rate for NO2 1-hr NAAQS

lb/hr

0.02

Startup Operation - Rectisol Flare

CO2 gas vent to Rectisol Flare until within product specification

Vent gas flow = 4,542 lbmol/hr = 430 x 10^6 Btu/hr, HHV

Sulfur in vent gas = 50 ppmv,max

Estimated Startup Rectisol Flare Emissions

	lb/hr
SO2	15
NOx	51.6
CO	34.4
$PM_{10}/PM_{2.5}$	1.3
VOC	0.6

(Emissions for NOX, CO, PM10, and VOC based on factors for natural gas pilots above)

Rectisol Flare

Rectisol startup vent gas to flare = 40 hr /yr

Pilot gas = 2628 x 10^6 Btu

Rectisol Flare Annual Emissions

	ton/yr		
	S/U and S/D	Pilot	Total
SO2	0.30	0.003	0.303
NOx	1.03	0.2	1.190
CO	0.69	0.1	0.793
$PM_{10}/PM_{2.5}$	0.03	0.004	0.030
VOC	0.01	0.002	0.013

Annualized Startup/Shut down Emission rate for NO2 1-hr NAAQS

lb/hr

0.24

Flare Stack Parameters

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Parameter	Rectisol Flare (during startup and shutdown)	Rectisol Flare (during normal pilot gas mode)	Rectisol Flare Annualized for NO2 1-hr NAAQS	Gasification Flare (during startup flare nitrogen)	Gasification Flare (during startup flare unshifted syngas gas)	Gasification Flare (during startup flare shifted syngas, sweet)	Gasification Flare (during normal pilot gas mode)	Gasification Flare annualized for NO2 1-hr NAAQS	SRU Flare (during Gasifier Startup and Shutdown)	SRU Flare (during normal pilot gas mode)	SRU Flare Annualized for NO2 1-hr NAAQS
Heat release rate for flare+pilot, (10^6 Btu/hr HHV)	430	0.3	2.263	2,926	2,386	2,413	0.5	4.526	36	0.3	0.464
H = Total Heat release rate (cal/s)	3.01E+07	2.10E+04	1.58E+05	2.05E+08	1.67E+08	1.69E+08	3.50E+04	3.17E+05	2.52E+06	2.10E+04	3.25E+04
Fb = Buoyancy flux	5.00E+02	3.49E-01	2.63E+00	3.40E+03	2.77E+03	2.80E+03	5.81E-01	5.26E+00	4.18E+01	3.49E-01	5.40E-01
Q_H = sensible heat release rate	1.35E+07	9.45E+03	7.13E+04	9.22E+07	7.52E+07	7.60E+07	1.57E+04	1.43E+05	1.13E+06	9.45E+03	1.46E+04
Actual Stack height (m)	76.2	76.2	76.2	76.2	76.2	76.2	76.2	76.2	76.2	76.2	76.2
GEP stack height for modeling (m)	65	65	65	65	65	65	65	65	65	65	65
AERMOD Input parameters											
He = Effective stack height (m) as calculated in SCREEN3	82.13	65.53	66.39	107.84	103.85	104.06	65.68	66.94	70.23	65.53	65.65
T = Stack temperature (K)	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273	1273
v = Exit velocity (m/s)	20	20	20	20	20	20	20	20	20	20	20
d = effective stack diameter (m)	3.636	0.096	0.264	9.486	8.565	8.614	0.124	0.373	1.052	0.096	0.119

Flare stack parameters are based on calculated using the SCREEN3 technique
Fb = Buoyancy flux = 1.66 x 10-5 x H
QH = sensible heat release rate = 0.45 x H
He = Effective stack height (m) = Hs + 4.56E-03 * H^0.478
BTU/hr to cal/sec 0.06999882

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Cooling Tower Operating Data and Emission Calculation				
Parameter	**Process**	**Power Block**	**ASU**	**Basis**
Cooling water (CW) circulation rate, gpm	162,582	95,500	44,876	Typical plant performance
CW circulation rate, million lb/hr	81	48	22	
CW dissolved solids, ppmw	9,000	9,000	2,000	(See note)
Drift, fraction of circulating CW	0.0005%	0.0005%	0.0005%	Expected BACT
PM10 emission rate, lb/hr	3.7	2.1	0.2	Calculated
PM10 emission rate, ton/yr	15.2	9.3	0.9	Calculated
PM2.5 emission rate, lb/hr	2.2	1.3	0.1	PM2.5 portion is equal to 60% of PM10
PM2.5 emission rate, ton/yr	9.1	5.6	0.6	PM2.5 portion is equal to 60% of PM10
Annual operation (hours/yr)	8314	8668	8314	
Cells per cooling tower	13	12	4	

Notes: Basis: Supplier data
Assumed maximum TDS in circulating cooling water, normally TDS will be less.
Each tower assumed to operate at full capacity, when operating.
Cooling water circulation rates and dissolved solids concentrations may vary, but in combination will not exceed the stated particulate emission rates.
Portion of PM10 that is PM2.5 60%

4/17/2012

Emergency Generator - Expected Emergency Operation and Maintenance

Total Hours of Operation	50	hr/yr
Generator Specification	2,922	Bhp

Generator Pollutant Emission Factors (per generator)

NOx (g/Bhp/hr)	0.50
CO (g/Bhp/hr)	2.60
VOC (g/Bhp/hr)	0.30
SO_2 (g/Bhp/hr)	N/A
PM_{10} = $PM_{2.5}$ (g/Bhp/hr)	0.07

Source: CARB Tier 4 Interim Standard

Generator Pollutant Emission Rates (per generator)

	Generator Emissions			
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/yr**
NOx	3.22	3.22	161.04	0.08
CO	16.75	16.75	837.43	0.42
VOC	1.93	1.93	96.63	0.05
SO_2	0.03	0.03	1.40	0.00
PM_{10} = $PM_{2.5}$	0.45	0.45	22.55	0.01

Fuel sulfur content =	15	ppmw
SO_2 emissions =	0.20	lb SO_2/1000 gal
Fuel flow	140.00	gal/hr

Pounds per day assumes 1 hour of operation for maintenance and testing per engine.

Please note that there are two generators; all emissions are shown for individual generators

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Modeling Worst-Case 1 hr Emissions (per generator)

		Annualized lb/hr for NO2 1-hr NAAQS
NOx (g/sec)	0.4	0.0184
CO (g/sec)	2.1	
SO_2 (g/sec)	0.004	

Only NOx, CO, and SO_2 are considered for an average 1-hour Ambient Air Quality Standard.

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

Modeling Worst-Case 3 hr Emissions (per generator)

SO_2 (lb/3-hr)	0.03
SO_2 (g/sec)	0.001

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
Pounds per 3-hr assumes two (2) hours of operation.

Modeling Worst-Case 8 hr Emissions (per generator)

CO (lb/8-hr)	16.75
CO (g/sec)	0.26

Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Pounds per 8-hr assumes two (2) hours of operation.

Modeling Worst-Case 24 Hour Emissions (per generator)

SO_2 (lb/24-hr)	0.03
SO_2 (g/sec)	0.0001
PM_{10} = $PM_{2.5}$ (lb/24-hr)	0.45
PM_{10} = $PM_{2.5}$ (g/sec)	0.002

Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.
Pounds per 24-hr assumes two (2) hours of operation.

Modeling Annual Average Emissions (per generator)

		Annual Emissions (tons/yr) per generator	both generators
NOx (g/sec)	0.002	0.081	0.161
CO (g/sec)	0.012	0.419	0.837
VOC (g/sec)	0.001	0.048	0.097
SO_2 (g/sec)	0.00002	0.001	0.001
PM_{10} = $PM_{2.5}$ (g/sec)	0.0003	0.011	0.023

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Fire Water Pump - Expected Emergency Operation and Maintenance

Total Hours of Operation	100	hr/yr
Fire Water Pump Specification	556	Bhp

Fire Water Pump Pollutant Emission Factors

NOx (g/Bhp/hr)	1.50
CO (g/Bhp/hr)	2.60
VOC (g/Bhp/hr)	0.14
SO_2 (g/Bhp/hr)	N/A
PM_{10} = $PM_{2.5}$ (g/Bhp/hr)	0.015

Source: CARB Tier 4 Interim Standard

Fire Water Pump Pollutant Emission Rates

	Fire Water Pump Emissions			
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/yr**
NOx	1.84	3.68	183.86	0.1
CO	3.19	6.37	318.69	0.2
VOC	0.17	0.34	17.16	0.01
SO_2	0.01	0.01	0.56	0.0003
PM_{10} = $PM_{2.5}$	0.02	0.04	1.84	0.00

Fuel sulfur content =	15	ppmw	Pounds per day assumes two (2) hours of operation for maintenance and testing.
SO_2 emissions =	0.20	lb SO_2/1000 gal	
Fuel flow	28.00	gal/hr	

Emergency Diesel Firewater Pump — Emissions Summary

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Modeling Worst-Case 1 hr Emissions

		Annualized lb/hr for NO2 1-hr NAAQS
NOx (g/sec)	0.2	0.02
CO (g/sec)	0.4	
SO_2 (g/sec)	0.0007	

Only NOx, CO, and SO_2 are considered for an average 1-hour Ambient Air Quality Standard

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

Modeling Worst-Case 3 hr Emissions

SO_2 (lb/3-hr)	0.01
SO_2 (g/sec)	0.0005

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
Pounds per 3-hr assumes two (2) hours of operation.

Modeling Worst-Case 8 hr Emissions

CO (lb/8-hr)	6.37
CO (g/sec)	0.1

Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Pounds per 8-hr assumes two (2) hours of operation.

Modeling Worst-Case 24 Hour Emissions

SO_2 (lb/24-hr)	0.01
SO_2 (g/sec)	0.0001
PM_{10} = $PM_{2.5}$ (lb/24-hr)	0.04
PM_{10} = $PM_{2.5}$ (g/sec)	0.0002

Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.
Pounds per 24-hr assumes two (2) hours of operation.

Modeling Annual Average Emissions

		tons/yr
NOx (g/sec)	0.003	0.092
CO (g/sec)	0.005	0.159
VOC (g/sec)	0.0002	0.009
SO_2 (g/sec)	0.00001	0.000
PM_{10} = $PM_{2.5}$ (g/sec)	0.00003	0.001

Ammonia Synthesis Plant Startup Heater

Maximum heat release	55	10^6 Btu/hr, HHV
Maximum annual usage:	7,700	10^6 Btu/yr, HHV
(equivalent to	140	hours @ full capacity)

Emission factors

	lb/10^6 Btu, HHV	Basis
SO2	0.00204	12.65 ppmv total sulfur in pipeline natural gas (max short-term)
NOx	0.011	Low NOx burner, 9 ppmvd (3% O2)
CO	0.037	50 ppmvd (3% O2)
$PM_{10}/PM_{2.5}$	0.005	Similar equipment from previous project
VOC	0.004	Similar equipment from previous project

	Max short-term lb/hr	Annual average ton/yr
SO2	0.1	0.0079
NOx	0.6	0.0420
CO	2.0	0.1425
$PM_{10}/PM_{2.5}$	0.3	0.0193
VOC	0.2	0.0154

Used only for Ammonia Plant Startup only.
Natural gas fuel

Annualized Startup Emission rate for NO2 1-hr NAAQS

lb/hr
0.010

Urea HP & LP Absorber Emission Calculation

Reference Plant			**HECA**		
Plant Capacity =	3,360	tpd (metric)	Plant Capacity =	1,701	stpd
Urea HP Absorber NH3 =	11	kg/hr	Urea HP Absorber NH3 =	11.1	lb/hr
Urea LP Absorber NH3 =	2	kg/hr	Urea LP Absorber NH3 =	2.0	lb/hr

Reference plant information is from technical proposal provided by UreaCasale for the SCS PurGen One project.

Urea Pastillation Emission Calculation

Reference Plant			**HECA**		
Plant Max Capacity =	3,855	stpd	Plant Capacity =	1,701	stpd
Total Air Flow =	21,000	m^3/hr	NH3 Emission =	1.02	lb/hr
Ammonia Concentration =	50	mg/m^3	Urea Dust Emission =	0.05	lb/hr
Urea Dust =	0.001	gr/dscf	Annual operating hours	8052	hours/year
			PM Annual Emissions =	0.20	tons/yr

Reference plant information provided by Sandvik Fellbach for the SCS PurGen One project.
All PM emissions are PM2.5 or smaller

Nitric Acid Plant Emission Calculation

HECA

Nitric Acid Production =	501	STPD
NOx Emissions Factor* =	0.20	lb/T
NOx Emissions =	4.18	lb/hr
NH3 Emissions =	0.5	lb/hr
Annual operating hours	8052	hours/year
NOx Annual Emissions =	16.8	tons/yr

*Emission factor based on use of the Udhe EnviNOx system. Approx 15 ppmv NOx in vent gas
50% NO2/NOx in-stack ratio used in NAAQS modeling

Ammonium Nitrate Plant Emission Calculation

HECA

Ammonium Nitrate Production =	636	STPD
PM Emissions =	0.20	lb/hr
Annual operating hours	8000	hours/year
PM Annual Emissions =	0.80	tons/yr

Vendor provided emission rate
All PM emissions are PM2.5 or smaller

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Material Handling Emissions							Stack Parameters for Modeling			
Emission Release Point	Operating Capacity		Flow	Grain Loading	Emissions		Stack Diameter	Stack Height	Stack velocity	Stack velocity
	hr/day	day/week	ACFM	gr/dscf	Total PM (lb/hr)	Total PM (tons/yr)	ft	ft	(ft/sec)	(m/s)
Coal/Coke Storage and Handling										
17 Coal Rail Unloading Station	8	5	20,000	0.001	0.17	0.18	3	30	47.2	14.4
18 Coal Transfer Tower	12	7	1,500	0.001	0.01	0.03	0.83	100	46.2	14.1
20 Coal/Coke Truck Unloading Station	12	5	80,000	0.001	0.69	1.07	6	60	47.2	14.4
22 Coal/Coke Transfer Tower B	12	5	1,500	0.001	0.01	0.02	0.83	100	46.2	14.1
19 Coal/Coke Crusher Building	12	7	1,500	0.001	0.01	0.03	0.83	100	46.2	14.1
Urea Storage and Handling										
30 Urea Bucket Elevator to Conveyor	24	7	1,500	0.001	0.01	0.06	0.83	50	46.2	14.1
31 Urea Transfer Tower 1	24	7	1500	0.001	0.01	0.06	0.83	100	46.2	14.1
32 Urea Transfer Tower 2	24	1.75	1500	0.001	0.01	0.01	0.83	100	46.2	14.1
33 Urea Transfer Tower 3	24	3.5	1500	0.001	0.01	0.03	0.83	100	46.2	14.1
34 Urea Transfer Tower 4	24	1.75	1500	0.001	0.01	0.01	0.83	100	46.2	14.1
35 Urea Transfer Tower 5	8	5	1500	0.001	0.01	0.01	0.83	100	46.2	14.1
23 Urea Loading Bldg Baghouse 1	8	5	20,000	0.001	0.17	0.18	3	30	47.2	14.4
24 Urea Loading Bldg Baghouse 2	8	5	10,000	0.001	0.09	0.09	2	30	53.1	16.2
Gasification Solids Storage and Handling										
25 Gasification Solids Bunker & Pad	24	7	-	-	0.02	0.09	NA			
28 Gasification Solids Transfer Tower	8	3	3,000	0.001	0.03	0.02	1.17	30	46.5	14.2
29 Gasification Solids Load-Out System	8	3	10,000	0.001	0.09	0.05	2	30	53.1	16.2
				Total =	**1.36**	**1.93**				

All PM emissions are PM2.5 or smaller

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Source	HRSG Stack[2] ON-Peak	HRSG Stack[2] OFF-Peak	Gasification Coal Dryer Stack[3]	Urea Plant Absorbers MP	Urea Plant Absorbers LP	Urea Pastillation Stack	Nitric Acid Plant Stack	Gasification Flare
Stack height, ft above grade[1]	213	213	305	130	50	50	145	250
Stack diameter, ft	23	23	16	1	1	1.5	8	9.8
Stack outlet temp, deg F	200	200	200	122	119	ambient	239	(NA)
Stack exit flow, act ft3/sec	22,357	16,953	3,852	19	19	111	860	varies per scenario
Stack exit velocity (ft/sec)	53.81	40.80	19.16	24.19	24.19	62.81	17.11	
Stack exit velocity (m/sec)	16.40	12.44	5.84	7.37	7.37	19.15	5.21	

Source	SRU Flare	Rectisol Flare	Cooling Towers (per cell)[4]	Tail Gas Oxidizer	Fire Pump Engine	Diesel Generator (ea.)	CO2 Vent	Aux Boiler	Ammonia Plant SU Heater	Ammonium Nitrate Vent
Stack height, ft above grade[1]	250	250	55	165	20	20	260	80	80	40
Stack diameter, ft	2	1.3	30	2.5	0.7	1.2	3.5	4.5	3.5	0.17
Stack outlet temp, deg F	(NA)	(NA)	75	1200	850	760	65	300	300	100
Stack exit flow, act ft3/sec	varies per scenario	varies per scenario	18,500	250	60	250	1,765	480	180	0.3
Stack exit velocity (ft/sec)			26.17	50.93	155.91	221.05	183.45	30.18	18.71	13.75
Stack exit velocity (m/sec)			7.98	15.52	47.52	67.38	55.92	9.20	5.70	4.19

Notes:
(1) Actual stack hieght for flares. Effective stack height for modeling was calculated based on GEP height of 65 meters. See Flare Stack Parameters tab in this workbook.
(2) Stack outlet temperature shown for HRSG is the estimated stack temperature after power cycle optimization. Case 1 On-Peak Power exit flow rate, Case 2 Off-Peak Power exit flow rate
(3) Flow rate shown in table for coal dryer is based on full load syn gas combustion for Case 4 (relatively constant for varying power plant loads and ambient temperatures).
(4) Nine cells estimated for power block cooling tower; 13 cells estimated for process cooling tower, and four cells estimated for the ASU cooling tower.
(5) Flare gas heat release, 10^6 Btu/hr, HHV; first value is normal pilot gas, second value is the maximum startup heat release

	Process Area											
	1	2	4	5	6	7	8	9	10	11	12	
	Methanol	Syn Gas	Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	TGTU Process Gas	Total
Compound	**Annual Fugitive Emissions with LDAR Application (ton/yr)**											
CO_2		0.74	20.08		0.69	1.82	0.49	0.81	0.84		5.72	31.19
CH_4		0.05	0.14			0.00	0.00	0.00	0.00			0.19
CO		4.16	0.42		0.00	0.00	0.00	0.00	0.00		0.03	4.62
H_2S		0.06	0.20		0.05	0.07	0.00	0.53	0.07	0.00	0.16	1.14
NH_3		0.00			0.07				0.09			0.16
COS		0.02				0.00		0.01	0.00		0.00	0.03
CH_3OH	4.02					2.18	0.88	0.00				7.09
C_3H_6				6.33								6.33
HCN									0.00			0.00
Total VOC	**4.02**	**0.02**	**0.00**	**6.33**	**0.00**	**2.18**	**0.88**	**0.01**	**0.00**	**0.00**	**0.00**	**13.45**
Total percentage of VOC content of gas in each process area	100.00%	0.15%	0.00%	100.00%	0.00%	53.51%	64.10%	0.54%	0.07%	0.00%	0.03%	

Note: The following compounds are included as VOCs, although not all compounds are found in the gas in each process area.
CH_3OH, C_3H_6, COS, and HCN

Summary by Volume Source for Modeling - Emissions are divided by number of Volume Sources

"GASIFICATION" (Area #2)

	lb/hr/volume	lb/yr/volume
CO	0.316	2,772.38
H_2S	4.19E-03	36.69
NH_3	9.74E-06	8.53E-02
CH_3OH		
C_3H_6		
HCN		

3 number of Volume Sources
28 horizontal dimension (m)
46.48 release ht (m)
13.02 horizontal dimension (m)
43.24 vertical dimension (m)

"SHIFT" (Area #4, 6)

	lb/hr/volume	lb/yr/volume
CO	4.84E-02	424.19
H_2S	2.81E-02	245.74
NH_3	7.83E-03	68.56
CH_3OH		
C_3H_6		
HCN		

2 number of Volume Sources
35 horizontal dimension (m)
6.10 release ht (m)
16.28 horizontal dimension (m)
5.67 vertical dimension (m)

"AGR" (Area #1, #5, #7, #8, #9)

	lb/hr/volume	lb/yr/volume
CO	6.32E-04	5.54
H_2S	1.37E-01	1195.86
NH_3		
CH_3OH	1.62E+00	14172.79
C_3H_6	1.44E+00	12657.98
HCN		

1 number of Volume Sources
48 horizontal dimension (m)
6.10 release ht (m)
22.33 horizontal dimension (m)
5.67 vertical dimension (m)

"Sour Water Stripper" (Area #10)

	lb/hr/volume	lb/yr/volume
CO	1.02E-03	8.94
H_2S	1.68E-02	146.89
NH_3	2.06E-02	180.69
CH_3OH		
C_3H_6		
HCN	1.31E-04	1.15

1 number of Volume Sources
16 horizontal dimension (m)
6.10 release ht (m)
7.44 horizontal dimension (m)
5.67 vertical dimension (m)

"SRU" (Area #11, #12)

	lb/hr/volume	lb/yr/volume
CO	3.08E-03	27.01
H_2S	1.89E-02	165.37
NH_3		
CH_3OH		
C_3H_6		
HCN		

2 number of Volume Sources
16 horizontal dimension (m)
6.10 release ht (m)
7.44 horizontal dimension (m)
5.67 vertical dimension (m)

Note: Selective LDAR program was applied to Areas # 1, #5, #7, #8, #9, #10 due to high uncontrolled emissions for the VOCs (methanol and propylene) and hydrogen sulfide

Summary of Transportation Vehicles and Routes

4/17/2012

Commodity Handled	Petcoke	Coal	Liquid Sulfur	Gasification	Ammonia	Urea	UAN	Equipment	Miscellaneous
Expected plant operation									
Expected plant operation is 8000 hours / year									
The plant will operate 24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day	24 hours / day
The plant will operate 333 days / year	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr	333 days / yr
Shipment by trucks	100 %	0 %	75 %	25 %	75 %	25 %	50 %	100 %	100 %
Shipment by train	0 %	100 %	25 %	75 %	25 %	75 %	50 %	0 %	0 %
Production rate									
Required Normal Flow / day	1,140 tons / day	4,580 tons / day	100 tons / day	839 tons / day	500 tons / day	833 tons / day	1,392 tons / day		
Required Normal Flow / year	380,000 tons / yr	1,525,000 tons / yr	33,000 tons / yr	280,000 tons / yr	167,000 tons / yr	280,000 tons / yr	464,000 tons / yr		
Required Maximum Flow day	1,368 tons / day (3)	6,107 tons / day (4)	200 tons / day (5)	1,678 tons / day (6)	1,000 tons / day (6)	1,666 tons / day (6)	2,784 tons / day (6)		
Truck Shipments									
Truck Capacity	25 tons / truck		25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck	25 tons / truck
Required trucks loads for normal operation / day	46 trucks / day		4 trucks / day	8 trucks / day	15 trucks / day	8 trucks / day	28 trucks / day	2 trucks / day	3 trucks / day
Required trucks loads for normal operation / yr	15,200 truck / yr		990 truck / yr	2,800 truck / yr	5,010 truck / yr	2,800 truck / yr	9,280 truck / yr		
Required trucks loads for maximum operation /day	55 trucks / day		8 trucks / day	17 trucks / day	30 trucks / day	17 trucks / day	56 trucks / day		
Train Shipments									
Railcar Capacity		117 tons / car	100 tons / car	100 tons / car	117 tons / car	117 tons / car	117 tons / car		
Assume a train has 13,000 ton capacity									
Required railcars for normal operation / day		39 cars / day	0.25 cars / day	6 cars / day	1 cars / day	5 cars / day	6 cars / day		
Required railcar loads for normal operation / yr		13,034 cars / yr	83 cars / yr	2,800 cars / yr	357 cars / yr	1,795 cars / yr	1,983 cars / yr		
Required railcars for maximum operation / day		200 cars / day	1 cars / day	16 cars / day	2 cars / day	11 cars / day	12 cars / day		
Basis	- 91% availability - 25% petcoke (heat input) - 25 ton/truck - 7 days/week receiving - 25% excess truck	- 91% availability - 75% coal (heat input) per - 117 tons/car - 100% coal for maximum - Rack sized to handle two	- 91% availability - High sulfur case - 100 - 25 ton/truck - Weekdays only - Can only move up to 25% of	- 91% availability - 75% coal max annual - 100% capable by rail - 25% capable by truck - Maximun is double the daily	- 91% availability - 500 t/d NH3 sales - 75% by truck - Ability to ship 7500 tons over	- 91% availability - 75% by rail -empty 45 day storage in 10 d '	- 91% availability - 75% by rail -empty 45 day storage in 10 d	'	
Traffic route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route	Truck Route
Destination/Origin	Carson Refinery	None	California Sulfur	Various	Various	Various	Various	Various	Various
Address	1801 E Sepulveda, Carson		2509 E Grant Street, Wilmington						
Distance	140 Miles		142 Miles	80 Mile radius	40 mile radius	40 mile radius	40 mile ratius	40 mile ratius	40 mile ratius
Route	Alameda 405 Fwy 5 Fwy Stockdale hwy Morris Road Station Road Station Road		Grant Henry Ford Alameda 405 Fwy 5 Fwy Stockdale hwy Morris Road Station Road	40 mile radius Station Road Morris Road Stockdale Hywy 5 Fwy	Station Road Morris Road Stockdale Hywy 5 Fwy	Station Road Morris Road Stockdale Hywy 5 Fwy	Station Road Morris Road Stockdale Hywy 5 Fwy	5 fwy Stockdale Hwy Dairy Road	5 fwy Stockdale Hwy Dairy Road
	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route	Rail Route
Destination/Origin	None	Elk Ranch New Mexico	In SJVAPCD	CEMEX, Victorville	Calamco	Oregon/Washington	Calamco	None	None
Address					Port Rd G15, Stockton, CA		Port Rd G15, Stockton, CA		
Distance		794 miles		198 miles	264 miles	628 Miles	264 miles		
Route		Kern County: 132.2 miles (County Line near Boron, CA to north prope Mine to Boron, CA: 662 miles Total Distance: 794.2 miles		SJVR/BNSF	SJVR/UPRR	SJVR/UPRR			

Notes

1) Equipment Maintenance Trucks are considered to be 2% of the total trucks per day for the feed and product operation.
2) Miscellaneous trucks are considered to be 3% of the total trucks per day for the feed and product operation.
3) The maximum flow rate of coke is ratioed up from the normal flow rate at 25% to 30% of feed
4) The maximum flow rate of coal is ratioed up from the normal flow rate at 75% to 100% of feed
5) The maximum flow rate of sulfur is 2 times the normal production
6) The maximum flow rate of these commodities is 2 times the normal production
7) The sources of flow data used in the Production Rate calculation were based on the flow rates provided in "Conference Note: Rail and Truck Traffic - Planning Session" and the "FertilizerProductMovement Update", 01-25-12.

4/17/2012

Calculations for Trucks Operation Modeling

Data Supplied By Client					
Parameter	Petcoke Trucks		Product Trucks		Miscellaneous Trucks
	Running Emissions	Idling Emissions	Running Emissions	Idling Emissions	Running Emissions
Distance Traveled (mi)*	0.96		2.49		2.20
Per Truck Idle Time (hr)		0.083		0.083	
Maximum number of trucks or loads:					
1-hr	6	6	13	13	5
3-hr	17	17	39	39	5
8-hr	44	44	104	104	5
24-hr	55	55	130	130	5
Annual average trucks or loads	15,200	15,200	20,880	20,880	1,818

EMFAC2007 Emission Factors + Fugitive Dust (g/mi or g/idle-hour) For Truck Model year 2010

	Petcoke Trucks		Product Trucks		Miscellaneous Trucks
Pollutant	Running Emissions (g/mile/trk)	Idling Emissions (g/idle-hour/trk)	Running Emissions (g/mile/trk)	Idling Emissions (g/idle-hour/trk)	Running Emissions (g/mile/trk)
CO	3.03	43.69	3.03	43.69	3.03
NOx	5.43	122.65	5.43	122.65	5.43
ROG	1.39	7.74	1.39	7.74	1.39
SOx	0.03	0.06	0.03	0.06	0.03
PM10 *	0.92	0.11	0.92	0.11	0.92
PM2.5 *	0.29	0.10	0.29	0.10	0.29

EMFAC2007 is the approved federal model for vehicle combustion emissions
* PM10 and PM2.5 includes fugitive dust factor for paved roads obtained from AP-42 Ch. 13 plus PM factors from EMFAC 2007
PM factors from EMFAC = combustion exhaust + tire wear + break wear
EMFAC emissions are for fleet year 2010 travelling at 10 mph.

1-hr Emission Rates for AERMOD (g/s) all trucks

	Petcoke Trucks		Product Trucks		Miscellaneous Trucks
Pollutant	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions
CO	4.424E-03	5.562E-03	2.726E-02	1.319E-02	1.010E-02
NOx	7.929E-03	1.561E-02	4.886E-02	3.702E-02	1.810E-02
ROG	2.028E-03	9.859E-04	1.250E-02	2.337E-03	4.629E-03
SOx	4.383E-05	7.894E-06	2.701E-04	1.871E-05	1.000E-04
PM10	1.340E-03	1.451E-05	8.255E-03	3.441E-05	3.058E-03
PM2.5	4.273E-04	1.324E-05	2.633E-03	3.139E-05	9.754E-04

3-hr Emission Rates for AERMOD (g/s) all trucks

	Petcoke Trucks		Product Trucks		Miscellaneous Trucks
Pollutant	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions
CO	4.424E-03	5.562E-03	2.726E-02	1.319E-02	1.010E-02
NOx	7.929E-03	1.561E-02	4.886E-02	3.702E-02	1.810E-02
ROG	2.028E-03	9.859E-04	1.250E-02	2.337E-03	4.629E-03
SOx	4.383E-05	7.894E-06	2.701E-04	1.871E-05	1.000E-04
PM10	1.340E-03	1.451E-05	8.255E-03	3.441E-05	3.058E-03
PM2.5	4.273E-04	1.324E-05	2.633E-03	3.139E-05	9.754E-04

8-hour Emission Rates for AERMOD (g/s) all trucks

	Coke and Coal Trucks (@ 10 mph)		Product Trucks (@ 10 mph)		Miscellaneous Trucks @ 10 mph
Pollutant	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions
CO	4.424E-03	5.562E-03	2.726E-02	1.319E-02	1.010E-02
NOx	7.929E-03	1.561E-02	4.886E-02	3.702E-02	1.810E-02
ROG	2.028E-03	9.859E-04	1.250E-02	2.337E-03	4.629E-03
SOx	4.383E-05	7.894E-06	2.701E-04	1.871E-05	1.000E-04
PM10	1.340E-03	1.451E-05	8.255E-03	3.441E-05	3.058E-03
PM2.5	4.273E-04	1.324E-05	2.633E-03	3.139E-05	9.754E-04

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24-hour Emission Rates for AERMOD (g/s) all trucks

Pollutant	Petcoke Trucks		Product Trucks		Miscellaneous Trucks
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions
CO	1.843E-03	2.318E-03	1.136E-02	5.495E-03	1.010E-02
NOx	3.304E-03	6.506E-03	2.036E-02	1.542E-02	1.810E-02
ROG	8.449E-04	4.108E-04	5.207E-03	0.000E+00	4.629E-03
SOx	1.826E-05	3.289E-06	1.125E-04	7.798E-06	1.000E-04
PM10	5.582E-04	6.047E-06	3.440E-03	1.434E-05	3.058E-03
PM2.5	1.781E-04	5.517E-06	1.097E-03	1.308E-05	9.754E-04

Annual Emission Rates for AERMOD (g/s) all trucks

Pollutant	Petcoke Trucks		Product Trucks		Miscellaneous Trucks
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions
CO	1.396E-03	1.755E-03	4.983E-03	2.411E-03	3.839E-04
NOx	2.501E-03	4.926E-03	8.931E-03	6.767E-03	6.880E-04
ROG	6.398E-04	3.110E-04	2.284E-03	4.273E-04	1.760E-04
SOx	1.383E-05	2.490E-06	4.937E-05	3.421E-06	3.803E-06
PM10	4.226E-04	4.579E-06	1.509E-03	6.290E-06	1.162E-04
PM2.5	1.348E-04	4.177E-06	4.813E-04	5.738E-06	3.708E-05

Volume, Line Sources

Guidance for Air Dispersion Modeling, SJVAPCD, 2007 and Section 1.2.2 of Volume II of ISC User's Guide			
2.3.2 Oyo=12W/2.15			
Truck Traveling vol src		Truck Idling pt src	
6	ft Release height	12.6	ft Release height
12	ft Width	0.1	m diam
66.98	ft init horz dim Syo	51.71	m/s vel
5.58	ft init vert dim Szo	366	K Temp
		199.134	F Temp

Volume, Stand Alone

Guidance for Air Dispersion Modeling, SJVAPCD, 2007	
2.3.2 + modelers judgement + ISC guidance	
Truck Traveling vol src	
6	ft Release height
12	ft Width
2.79	ft init horz dim Syo
5.58	ft init vert dim Szo

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Transportation Information		Notes
- Onsite Vehicle =	20 trucks	- Information Provided By Applicant
- Vehicle year=	2010	- Information Provided By Applicant
- Maximum annual mileage =	10,000 miles/truck-year	- All routine vehicular traffic is anticipated to travel exclusively on paved roads
		- Assumed 15 mph average speed within HECA facility

Calculations for Trucks Operation Modeling per Truck

	Onsite O&M Trucks
Mileage	
1-hr	1
3-hr	3
8-hr	9
24-hr	27
Annual average trucks or loads	10000

EMFAC2007 Emission Factors (g/mi) For Truck Model year 2010

	AERMOD	
Pollutant	Gas LHDT1	Diesel LHDT2
CO	0.229	0.920
NOx	0.064	0.672
ROG	0.014	0.085
SOx	0.011	0.005
PM10 *	0.167	0.176
PM2.5 *	0.054	0.062

EMFAC2007 is the approved federal model for vehicle combustion emissions
* PM10 and PM2.5 includes fugitive dust factor for paved roads obtained from AP-42 Ch. 13 plus PM factors from EMFAC 2007
PM factors from EMFAC = combustion exhaust + tire wear + break wear
EMFAC emissions are for fleet year 2010 travelling at 15 mph.

1-hr Emission Rates for AERMOD (g/s) all trucks

	AERMOD	
Pollutant	Gas LHDT1	Diesel LHDT2
CO	1.45E-03	5.83E-03
NOx	4.06E-04	4.26E-03
ROG	8.88E-05	5.39E-04
SOx	6.98E-05	3.17E-05
PM10	1.06E-03	1.11E-03
PM2.5	3.40E-04	3.91E-04

3-hr Emission Rates for AERMOD (g/s) all trucks

	AERMOD	
Pollutant	Gas LHDT1	Diesel LHDT2
CO	1.45E-03	5.83E-03
NOx	4.06E-04	4.26E-03
ROG	8.88E-05	5.39E-04
SOx	6.98E-05	3.17E-05
PM10	1.06E-03	1.11E-03
PM2.5	3.40E-04	3.91E-04

8-hour Emission Rates for AERMOD (g/s) all trucks

	AERMOD	
Pollutant	Gas LHDT1	Diesel LHDT2
CO	1.45E-03	5.83E-03
NOx	4.06E-04	4.26E-03
ROG	8.88E-05	5.39E-04
SOx	6.98E-05	3.17E-05
PM10	1.06E-03	1.11E-03
PM2.5	3.40E-04	3.91E-04

24-hour Emission Rates for AERMOD (g/s) all trucks

	AERMOD	
Pollutant	Gas LHDT1	Diesel LHDT2
CO	1.45E-03	5.83E-03
NOx	4.06E-04	4.26E-03
ROG	8.88E-05	5.39E-04
SOx	6.98E-05	3.17E-05
PM10	1.06E-03	1.11E-03
PM2.5	3.40E-04	3.91E-04

Annual Emission Rates for AERMOD (g/s) all trucks

	AERMOD	
Pollutant	Gas LHDT1	Diesel LHDT2
CO	1.45E-03	5.83E-03
NOx	4.06E-04	4.26E-03
ROG	8.88E-05	5.39E-04
SOx	6.98E-05	3.17E-05
PM10	1.06E-03	1.11E-03
PM2.5	3.40E-04	3.91E-04

Fugitive Dust on Paved Road

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AP 42 13.2.1 Paved Roads, updated January 2011

For a daily basis,
E = [k (sL)^0.91 x (W)^1.02](1-P/4N) (2)

P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period
W = average weight (tons) of vehicles traveling the road
k = particle size multiplier for particle size range and units of interest
sL = road surface silt loading (g/m^2)

	k
	g/VMT
PM2.5	0.25
PM10	1.00

Table 13.2.1-1
PARTICLE SIZE MULTIPLIERS FOR PAVED ROAD EQUATION

Large Trucks

				Empty truck	full truck	Load Capacity	
W=	17.5	tons, average		5	30	25	tons
sL=	0.031	g/m2	Default value from URBEMIS 9.2 for Kern County				
P=	36	days/year	Buttonwillow Station 1940-2011, WRCC				

E=
0.19149 g/VMT PM2.5 large delivery trucks
0.76594 g/VMT PM10 large delivery trucks

Operation and Maintenance Vehicles

W=	3	tons	
sL=	0.031	g/m2	Default value from URBEMIS 9.2 for Kern County
P=	36	days/year	Buttonwillow Station 1940-2011, WRCC

E=
0.03169 g/VMT PM2.5 large delivery trucks
0.12675 g/VMT PM10 large delivery trucks
#vol sources= 10

Fugitive Dust on Paved Road

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Fertilizer Product + Sulfur Product trucks + Gas Solids trucks + Misc trucks

102	max trucks/day for Ammonia + Urea + UAN	24 hrs/day
8	max trucks/day for Sulfur	
17	max trucks/day gas solids	
3	miscellaneous truck along this path	
130	Total product trucks max/day	

4000 meters, approximate length of road for product trucks: eastern fenceline to southern fenceline to middle loop and back out the opposite way
2.49 miles

0.47593 grams PM2.5/truck/day	62.059 g PM2.5/day for all product trucks	2.5858 g PM2.5/hr
1.90373 grams PM10/truck/day	248.237 g PM10/day for all product trucks	10.3432 g PM10/hr

volume source in model
73 3.5422E-02 g PM2.5/hr/volume source
1.4169E-01 g PM10/hr/volume source

Coke feedstock trucks (no coal by truck)

55 max feedstock trucks/day

1539 meters, approximate length of road loop to truck feedstock unloading facility on east side
0.96 miles

0.18312 grams PM2.5/truck/day	10.071 g PM2.5/day for all product trucks	0.4196 g PM2.5/hr
0.73246 grams PM10/truck/day	40.285 g PM10/day for all product trucks	1.6786 g PM10/hr

volume source in model
34 1.2342E-02 g PM2.5/hr/volume source
4.9369E-02 g PM10/hr/volume source

Miscellaneous Delivery Trucks

5 max trucks/day

3540 meters, approximate length of road from end of product truck south road, along southern fenceline, north toward main site, to parking lot and back
2.20 miles

0.421 grams PM2.5/truck/day	2.299 g PM2.5/day for all product trucks	0.0958 g PM2.5/hr
1.685 grams PM10/truck/day	9.196 g PM10/day for all product trucks	0.3832 g PM10/hr

volume source in model
5 1.9158E-02 g PM2.5/hr/volume source
7.6631E-02 g PM10/hr/volume source

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Assumed Number of Unit Trains (incoming/outgoing)

Averaging Period	Coal Unit Trains (incoming)	Unit Trains of Product (outgoing)	Maximum Total Trains per period
1-hr	1	1	1
3-hr	1	1	2
8-hr	2	1	3
24-hr	2	1	3
Annual average unit trains	109	153	262

# Cars Per train	120	46
maximum # Cars Per day	200-240	42-46

	Switching Enigne/ Rail car movers	Line-Haul Engine for Coal Train	Line-Haul Engine for Product Trains
Engine Power Rating (hp)		4400	3000
Notch Operation		1	1
Notch percentage of hp		5.0%	5.0%
Avg Notch horsepower	260	220	150
# of engines per train	1	2	2
hours to unload/load each train		2	1
max operating hours (hrs/day)	8		
max operating hours (hrs/year)	1248		

The majority of the time the line-haul engine will operate in Notch 1 or idling, therefore emissions were conservatively estimated for Notch 1 horsepower.

Notch percentage presented in PORT OF LONG BEACH AIR EMISSIONS INVENTORY for 2007 (POLB, Jan 2009) derived from EPA data.

For each coal train it takes 2 hours to complete the onsite loop to unload

For each product train it takes 1 hour to load

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Switching Engine Emission Factors	CO	NOx	PM10	PM2.5	SO2	VOC
Tier 3 Emission Factor (g/bhp-hr)	2.4	5.0	0.10	0.097	0.124	0.63
Emissions (lbs/hr /engine)	1.37	2.86	0.06	0.06	0.07	0.36
Line-Haul Emission Factors						
Tier 3 Emission Factor (g/bhp-hr)	1.50	5.50	0.10	0.10	0.09	0.32
Coal Train Emissions (lbs/hr /engine)	0.73	2.67	0.05	0.05	0.04	0.15
Product Train Emissions (lbs/hr /engine)	0.50	1.82	0.03	0.03	0.03	0.10

1-hr Emission Rates

	CO	NOx	PM10	PM2.5	SO2	VOC
	1-hr Emission Rates (lb/hr) all trains					
Switching engines	1.37	2.86	0.06	0.06	0.07	0.36
Line-haul coal engines	1.45	5.33	0.10	0.09	0.09	0.31
	1-hr Emission Rates for AERMOD (lb/hr) all trains divided by number of volume sources					
All On-site Trains	2.7E-02	7.9E-02	1.5E-03	1.4E-03	1.5E-03	6.4E-03

During a given hour either the line-haul engines for the coal train or product train operate, not both, thus emissions from the larger coal trains are only included in the peak hour emissions.

3-hr Emission Rates

	CO	NOx	PM10	PM2.5	SO2	VOC
	3-hr Emission Rates (lb/period) all trains					
Switching engines	4.12	8.59	0.17	0.17	0.21	1.09
Line-haul coal engines	2.91	10.66	0.19	0.19	0.18	0.61
Line-haul product engines	0.99	3.63	0.07	0.06	0.06	0.21
	3-hr Emission Rates for AERMOD (lb/hr) all trains divided by number of volume sources					
All On-site Trains	2.6E-02	7.3E-02	1.4E-03	1.3E-03	1.4E-03	6.1E-03

In the maximum operations 3 hour period, the switching engine operates up to 3 hours, 1 coal train unloads in 2 hours and 1 product train loads in 1 hour.

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8-hour Emission Rates

	CO	NOx	PM10	PM2.5	SO2	VOC
	8-hr Emission Rates (lb/period) all trains					
Switching engines	11.00	22.91	0.46	0.44	0.57	2.89
Line-haul coal engines	5.81	21.32	0.39	0.38	0.35	1.22
Line-haul product engines	0.99	3.63	0.07	0.06	0.06	0.21
	8-hr Emission Rates for AERMOD (lb/hr) all trains divided by number of volume sources					
All On-site Trains	2.1E-02	5.8E-02	1.1E-03	1.1E-03	1.2E-03	5.2E-03

In the maximum operations 8 hour period, the switching engine operates up to 8 hours, 2 coal train unloads in 2 hours each and 1 product train loads in 1 hour.

24-hour Emission Rates

	CO	NOx	PM10	PM2.5	SO2	VOC
	24-hr Emission Rates (lb/period) all trains					
Switching engines	11.00	22.91	0.46	0.44	0.57	2.89
Line-haul coal engines	5.81	21.32	0.39	0.38	0.35	1.22
Line-haul product engines	0.99	3.63	0.07	0.06	0.06	0.21
	24-hr Emission Rates for AERMOD (lb/hr) all trains divided by number of volume sources					
All On-site Trains	7.1E-03	1.9E-02	3.7E-04	3.5E-04	3.9E-04	1.7E-03

In the maximum operations 24 hour period, the switching engine operates up to 8 hours, 2 coal train unloads in 2 hours each and 1 product train loads in 1 hour.

Annual Emission Rates

	CO	NOx	PM10	PM2.5	SO2	VOC
	Annual Emission Rates (tons/period) all trains					
Switching engines	0.86	1.79	0.04	0.03	0.04	0.23
Line-haul coal engines	0.16	0.58	0.01	0.01	0.01	0.03
Line-haul product engines	0.08	0.28	0.01	0.00	0.00	0.02
	Annual Emission Rates for AERMOD (tons/yr) all trains divided by number of volume sources					
All On-site Trains	1.0E-02	2.5E-02	4.9E-04	4.8E-04	5.6E-04	2.6E-03

AERMOD source parameters
Volume sources spaces every 20 widths

Width	10	ft
Release Height	15	ft
Sigma Y	93	ft
Sigma Z	14	ft
# of volumes	104	

Guidance for Air Dispersion Modeling, SJVAPCD, 2007 and Section 1.2.2 of Volume II of ISC User's Guide

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Emission Factors

40 CFR Part 1033

Table 2 of 1033.101 Switch Locomotive Emission Standards

		Standards (g/bhp-hr)			
Year of original manufacture	**Tier of standards**	**CO**	**NOx**	**PM**	**HC**
1973-2001	Tier 0	8.0	11.8	0.26	2.1
2002-2004	Tier 1	2.5	11	0.26	1.2
2004-2010	Tier 2	2.4	8.1	0.13	0.60
2011-2014	Tier 3	2.4	5.0	0.10	0.60
2015 or later	Tier 4	2.4	1.3	0.03	0.14

Table 1 to §1033.101—Line-Haul Locomotive Emission Standards

		Standards (g/bhp-hr)			
Year of original manufacture	**Tier of standards**	**CO**	**NO_X**	**PM**	**HC**
1973–1992	Tier 0	5	8	0.22	1
1993–2004	Tier 1	2.2	7.4	0.22	0.55
2005–2011	Tier 2	1.5	5.5	0.10	0.3
2012–2014	Tier 3	1.5	5.5	0.10	0.3
2015 or later	Tier 4	1.5	1.3	0.03	0.14

Reference: 40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards

Emission Factors For all Locomotives			
SOx	**CO_2**	**CH_4**	**N_2O**
g/gal	g/gal	g/gal	g/gal
1.88	10217	0.80	0.26

Locomotive Application	Conversion Factor (bhp-hr/gal)
Large Line-haul & Passenger	20.8
Small Line-haul	18.2
Switching	15.2

Notes:

New line-haul engines will be AC locomotives such as the GE Evolution Series, that meet Tier 3 emissions

New switching engines will meet Tier 3 emissions, they may be the Titan Trackmobile railcar movers or similar

EPA's Technical Highlights: Emission Factors for Locomotives, 2009 (http://www.epa.gov/nonroad/locomotv/420f09025.pdf).

Based on 300 ppm sulfur diesel fuel.

CH_4 and N_2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for

VOC emissions can be assumed to be equal to 1.053 times the HC emissions

$PM_{2.5}$ Fraction of PM_{10}, = 0.97

Appendix E

Responses to PM2.5 Cooling Tower Data Requests

from CEC and USEPA

APPLICANT RESPONSES TO

CALIFORNIA ENERGY COMMISSION AND ENVIRONMENTAL PROTECTION AGENCY COMMENTS ON THE

PRELIMINARY DETERMINATION OF COMPLIANCE FOR THE HYDROGEN ENERGY CALIFORNIA (HECA) PROJECT (08-AFC-8)

Prepared for:

San Joaquin Valley Air Pollution Control District

Project Number S-1093741

Kern County, CA

Prepared on behalf of:

Hydrogen Energy California LLC

September 14, 2010

URS

ATTACHMENTS

Attachment CEC-3-1	CEIDARS Database Query for Cooling Towers
Attachment CEC-3-2	CEIDARS Power Plant Cooling Tower Emissions
Attachment CEC-3-3	Calculated PM_{10} and $PM_{2.5}$ Cooling Tower Emission Factors as a Function of Recirculating Water TDS
Attachment CEC-3-4	Response to CEC Data Request #18

RESPONSES TO CEC COMMENTS

CEC COMMENT

3. Cooling Tower PM2.5 Fraction Assumption: ***Staff believes that the rationale used by the applicant for the ratio of particulate matter less than 2.5 microns (PM2.5) to particulate matter less than 10 microns (PM10) of 0.6:1 for the cooling tower emissions is flawed. The rationale provided by the applicant notes that this ratio is cited in the South Coast Air Quality Management District's (SCAQMD's) particulate size fraction in the California Emission Inventory Development and Reporting System (CEIDARS) table from the SCAQMD CEQA website. However, the CEIDARS particulate size fraction data was originally produced by the California Air Resource Board (ARB) and review of the original CEIDARS particulate size fraction table from ARB shows that there is no cooling tower category and that the "other" category values have been used by SCAQMD in lieu of other available data for cooling towers in their version of the CEIDARS table. This shows that this particulate size fraction data is not specific to cooling towers and is not technically supportable. Staff is willing to accept a defendable cooling tower particulate size fraction reference; however, to date staff is not aware of such a defendable reference. Staff believes that the District should investigate this further and if possible provide a more technically defensible particulate size fraction reference and revise the cooling tower particulate matter (PM10 and PM2.5) emissions appropriately. If no specific particulate size fraction data reference for cooling towers is available, the District should assume 100 percent of the PM10 is PM2.5.***

RESPONSE

The cooling tower total PM emissions are based on the maximum expected total dissolved solids in the cooling water, annual circulating water rate, and the use of a high-efficiency drift eliminator. The Applicant conservatively estimated that total PM emitted from the cooling tower will be equal to PM_{10} in diameter, and the quantity of PM emissions that are equal to $PM_{2.5}$ will be 60 percent of the PM_{10} emissions (a fraction or ratio of 0.6). This ratio used by the Applicant is based on the several justifications described below.

1. The "South Coast Air Quality Management District (SCAQMD) – Final Methodology to Calculate $PM_{2.5}$ and $PM_{2.5}$ Significance Thresholds, Appendix A – Updated California Emission Inventory Data and Reporting System (CEIDARS) Table with $PM_{2.5}$ Fractions[1]" provides the cooling tower ratios of 0.7 for the PM_{10} fraction of total PM, 0.6 for the $PM_{2.5}$ fraction of PM_{10}, and 0.42 for the $PM_{2.5}$ fraction of total PM. The Applicant consulted with SCAQMD staff and confirmed these PM size fractions were derived from PM profiles in the CEIDARS developed by the California Air Resources Board (CARB). The Applicant also confirmed that SCAQMD examined carefully, approved, and officially adopted this document in October 2006. Since then, SCAQMD has required all California Environmental Quality Act/National Environmental Policy Act projects to use this methodology and its PM size fractions to estimate their PM, PM_{10}, and $PM_{2.5}$ emissions from cooling towers. Therefore, the use of the 0.6 ratio of $PM_{2.5}$ to

[1] Final Methodology to Calculate $PM_{2.5}$ and $PM_{2.5}$ Significance Thresholds (October 2006) from http://www.aqmd.gov/ceqa/handbook/PM2_5/finalmeth.doc; and its Appendix A – Updated CEIDARS Table with $PM_{2.5}$ Fractions from http://www.aqmd.gov/ceqa/handbook/PM2_5/finalAppA.doc.

PM_{10} provided by this SCAQMD document is valid for estimating the HECA Project cooling tower $PM_{2.5}$ emissions, although the $PM_{2.5}$ emissions will be overestimated due to the assumption that all PM emissions are comprised of PM_{10}.

2. The Applicant conducted a query for cooling towers in California on the CEIDARS[2]. The query results show that all of the cooling towers from different source categories in California in 1995, 2000, 2005, and 2008 have an average $PM_{2.5}$-to-PM_{10} ratio of 0.636, and an average $PM_{2.5}$–to-PM ratio of 0.441 (see Attachment CEC-3-1). In addition, the Applicant, with assistance from CARB emission inventory staff (Gabe Ruiz and Darryl Look), gathered all the California power plant cooling tower emissions from CEIDARS (see Attachment CEC-3-2). Because only PM emissions were measured, $PM_{2.5}$ emissions are estimated from PM emissions. Attachment CEC-3-2 and Applicant discussions with CARB staff confirmed that the 0.7/0.6/0.42 PM/PM_{10}/$PM_{2.5}$ ratios were applied to most of the power plant cooling tower emission estimates. The average $PM_{2.5}$ fraction of PM_{10} is 0.633, and the average $PM_{2.5}$ fraction of PM is 0.478 for all power plant cooling towers in California. The $PM_{2.5}$ fractions of PM_{10} from the CEIDARS database for cooling towers from power plant cooling towers and from different source categories are very similar to the fraction the Applicant used in its cooling tower $PM_{2.5}$ emissions estimations. Therefore, in calculating the cooling tower PM emissions, the Applicant has accurately presented the $PM_{2.5}$ portion of PM_{10} emissions, and furthermore, by assuming 100 percent of the total PM emissions to be PM_{10}, the Applicant has significantly overestimated the $PM_{2.5}$ emissions.

3. The assumption that 100 percent of the PM emitted from a cooling tower is smaller than 2.5 microns is too conservative from a technical perspective. The drift droplets generally contain the chemical impurities (or minerals) in the water circulating through the tower, and these impurities can be converted to airborne emissions. There are currently few papers about PM_{10}/$PM_{2.5}$ emission factors for mechanical draft cooling tower processes. One good reference[3] from Joel Reisman and Gorden Frisbie confirms the point that only a small amount of the circulating water may be entrained in the air stream, and it appears that most of the particles emitted from the cooling tower are larger than PM_{10}. According to the conclusion of this paper, 85 percent of the mass that is emitted is larger than 10 microns, and only 15 percent is less than 10 microns. The Applicant also consulted with EPA Staff (J. David Mobley, Deputy Director, Atmospheric Modeling and Analysis Division, National Exposure Research Laboratory; Lee Beck, Senior Project Engineer, Emissions Characterization & Prevention Branch, Air Pollution Prevention and Control Division), and the staff agree with the methodology and conclusion of this paper.

4. It should be reiterated that the PM_{10} emissions from the cooling towers at HECA were estimated using U.S. EPA's AP-42 guidance[4] that conservatively assumes that all dissolved solids in the circulating water will be converted to airborne

[2] CARB Emission Inventory Database (California Emission Inventory Development and Reporting System, CEIDARS) from http://www.arb.ca.gov/app/emsinv/emssumcat.php.
[3] Reisman, J. and Frisbie, G. (2002), Calculating realistic PM_{10} emissions from cooling towers. Environmental Progress, 21: 127–130. doi: 10.1002/ep.670210216.
[4] AP-42, CH 13.4: Wet Cooling Towers: (http://www.EPA.gov/ttnchie1/ap42/ch13/final/c13s04.pdf).

PM_{10}. The AP-42 document states " a *conservatively high* PM_{10} emission factor can be obtained by (a) multiplying the total liquid drift factor by the total dissolved solids (TDS) fraction in the circulating water and (b) assuming that, once the water evaporates, all remaining solid particles are within the PM_{10} size range." This U.S. EPA guidance clearly describes that cooling tower emissions of PM_{10}, and thus $PM_{2.5}$, that are calculated with this technique are overestimated.

5. Data from the 2006 Micheletti study, "Atmospheric Emissions from Evaporative Cooling Towers"[5], confirm that the assumption that of all the particulate emissions are PM_{10} is an exaggeration. Mr. Micheletti calculated PM_{10} and $PM_{2.5}$ emission factors that are at least an order of magnitude less than the small particulate emissions that would be calculated using the U.S. EPA's conservatively high method. Even when Mr. Micheletti adjusted the U.S. EPA particulate emission factor for changes in drift rate and recirculating water TDS concentration, he calculated PM_{10} and $PM_{2.5}$ emission factors that are noticeably lower (see Attachment CEC-3-3). He determined that the fatal flaw in the U.S. EPA's method is the assumption that all of the total dissolved solids in the drift become PM_{10} or $PM_{2.5}$.

6. The CEC commissioned a study[6] of environmental effect from saltwater cooling towers. Although the focus of this study was the effects from saltwater cooling towers, some of the data are derived from non-saltwater cooling towers. The CEC study references the Micheletti study and agrees with the conclusion that "only a small fraction (less than 15%) of the residual particles will have an aerodynamic diameter of less than 10 microns", although they warn there may be uncertainties in the calculations. This study shows that the CEC believes that significantly less than 100% of the particulate matter emitted from cooling towers is PM_{10} and $PM_{2.5}$.

Compliance with the PM emissions from the cooling tower will be demonstrated through PDOC Conditions 14 and 15.

Based on the data presented above, in the ATC application, in the response to CEC Data Request 18, and presented by SJVAPCD in the PDOC, the Applicant conservatively assumed all PM emissions were 10 microns or smaller and 60 percent of those emissions were 2.5 microns or smaller. In addition, the Applicant overestimated the PM_{10} emissions by assuming that all PM is 10 microns or smaller. The Applicant believes the evaluation of the $PM_{2.5}$ emissions from the cooling tower presented in the PDOC is valid, and no change to the PDOC is warranted for the cooling tower $PM_{2.5}$ emissions.

[5] Micheletti, W.C., 2006. "Atmospheric Emissions from Evaporative Cooling Towers." CTI Journal. Vol. 27, No. 1.
[6] CEC, Performance, Cost, And Environmental Effects Of Saltwater Cooling Towers, January 2010, CEC-500-2008-043.

ATTACHMENT CEC-3-1
CEIDARS DATABASE QUERY for COOLING TOWERS

DATA_SO	YEAR	AREA	SEASON	EMISSION_TYPE	SRC_TYPE	EIC	EICSUMN	EICSOUN	EICMATN	EICSUBN	TOG	ROG	COT	NOX	SOX	PM	PM10	PM2_5	PM2.5 Fraction of Total PM	PM10 Fraction of Total PM	PM2.5 Fraction of PM10
																SCAQMD CIEDARS data base summary			0.420	0.700	0.600
2009_Alma	2008	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	430-338-0	MINERAL PROCESSES	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0002	0.0001	0.0001	0.500	0.500	1.000
2009_Alma	2008	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	420-338-0	FOOD AND AGRICULTURE	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.1638	0.1146	0.0689	0.421	0.700	0.601
2009_Alma	2008	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	410-338-0	CHEMICAL	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0.0138	0.0096	0	0	0	0.1142	0.08	0.0479	0.419	0.701	0.599
2009_Alma	2008	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	320-338-0	PETROLEUM REFINING	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	2.1388	2.0747	0	0	0	2.2645	1.4118	1.2111	0.535	0.623	0.858
2009_Alma	2008	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	499-338-0	OTHER (INDUSTRIAL PROCESSES)	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0.0194	0.0136	0	0	0	0.9743	0.6836	0.4095	0.420	0.702	0.599
2009_Alma	2008	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	470-338-0	ELECTRONICS	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0201	0.0142	0.0084	0.418	0.706	0.592
2009_Alma	2008	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	460-338-0	GLASS AND RELATED PRODUCTS	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0336	0.0235	0.0141	0.420	0.699	0.600
2009_Alma	2008	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	450-338-0	WOOD AND PAPER	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0034	0.0025	0.0014	0.412	0.735	0.560
2009_Alma	2008	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	440-338-0	METAL PROCESSES	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.1705	0.1194	0.0716	0.420	0.700	0.600
																			0.440	**0.674**	**0.668**
2009_Alma	2005	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	499-338-0	OTHER (INDUSTRIAL PROCESSES)	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0.0136	0.0096	0	0	0	0.1477	0.1046	0.0621	0.420	0.708	0.594
2009_Alma	2005	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	470-338-0	ELECTRONICS	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.009	0.0063	0.0037	0.411	0.700	0.587
2009_Alma	2005	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	420-338-0	FOOD AND AGRICULTURE	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0094	0.0066	0.004	0.426	0.702	0.606
2009_Alma	2005	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	320-338-0	PETROLEUM REFINING	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	2.658	2.617	0	0	0	0.3166	0.1931	0.1757	0.555	0.610	0.910
2009_Alma	2005	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	410-338-0	CHEMICAL	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0.0042	0.0029	0	0	0	0	0	0			
2009_Alma	2005	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	310-338-0	OIL AND GAS PRODUCTION	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0072	0.0044	0.004	0.556	0.611	0.909
2009_Alma	2005	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	440-338-0	METAL PROCESSES	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0003	0.0002	0.0001	0.333	0.667	0.500
2009_Alma	2005	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	450-338-0	WOOD AND PAPER	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0071	0.005	0.003	0.423	0.704	0.600
																			0.446	**0.672**	**0.672**
2009_Alma	2000	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	410-338-0	CHEMICAL	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0.0036	0.0025	0	0	0	0.1997	0.1605	0.0839	0.420	0.804	0.523
2009_Alma	2000	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	330-338-0	PETROLEUM MARKETING	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0046	0.0032	0.0019	0.413	0.696	0.594
2009_Alma	2000	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	499-338-0	OTHER (INDUSTRIAL PROCESSES)	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0702	0.0557	0.0303	0.432	0.793	0.544
2009_Alma	2000	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	420-338-0	FOOD AND AGRICULTURE	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0063	0.0059	0.0026	0.413	0.937	0.441
2009_Alma	2000	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	470-338-0	ELECTRONICS	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.005	0.0035	0.0021	0.420	0.700	0.600
2009_Alma	2000	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	460-338-0	GLASS AND RELATED PRODUCTS	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0012	0.0008	0.0005	0.417	0.667	0.625
2009_Alma	2000	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	320-338-0	PETROLEUM REFINING	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	2.1455	2.0528	0	0	0	0.0934	0.057	0.0518	0.555	0.610	0.909
																			0.438	**0.744**	**0.605**
2009_Alma	1995	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	320-338-0	PETROLEUM REFINING	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	2.012	2.012	0	0	0	0.0008	0.0005	0.0004	0.500	0.625	0.800
2009_Alma	1995	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	410-338-0	CHEMICAL	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.2863	0.2475	0.1202	0.420	0.864	0.486
2009_Alma	1995	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	420-338-0	FOOD AND AGRICULTURE	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0047	0.0033	0.002	0.426	0.702	0.606
2009_Alma	1995	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	499-338-0	OTHER (INDUSTRIAL PROCESSES)	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0573	0.0437	0.0241	0.421	0.763	0.551
2009_Alma	1995	Statewide	Annual Ave	Grown and Controlled	STATIONAR'	460-338-0	GLASS AND RELATED PRODUCTS	COOLING TOWERS	HYDROCARBON COI	SUB-CATEGORY UN:	0	0	0	0	0	0.0033	0.0033	0.0014	0.424	1.000	0.424
																			0.438	**0.791**	**0.573**
							OTHER (INDUSTRIAL PROCESSES)											average	0.423	0.741	0.572
				Source														average all	0.441	0.712	0.636
				http://www.arb.ca.gov/app/emsinv/emssumcat.php																	

ATTACHMENT CEC-3-2
CEIDARS DATABASE QUERY for POWER PLANT COOLING TOWER EMISSIONS

Cooling Tower PM, PM10, PM2_5 Emissions in tons per year selected by SCC= 38500101

CO	AB	DIS	FACID	FNAME	DEV	PROID	PRDESC	SCC	SCC1N	SCC3N	SCC6N	PM	PM10	PM2_5	PM2.5 Fraction of Total PM	PM10 Fraction of Total PM	PM2.5 Fraction of PM10
33	SC	SC	129816	INLAND EMPIRE ENERGY CENTER, LLC	12	1	800-MW NATURAL GAS-FIRED, COMBINED-CYCLE ELECTRIC GENERATING	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.4	0.28	0.168	0.420	0.700	0.600
33	SC	SC	129816	INLAND EMPIRE ENERGY CENTER, LLC	11	1	800-MW NATURAL GAS-FIRED, COMBINED-CYCLE ELECTRIC GENERATING	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.64	0.448	0.2688	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	17	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
34	SV	SAC	193	CARSON ENERGY/SMUD	3	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.762635714	0.533845	0.320307	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	11	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
34	SV	SAC	3456	SMUD COSUMNES POWER PLANT	3	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	1.843171429	1.29022	0.774132	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	15	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
34	SV	SAC	195	SACRAMENTO COGENERATION AUTHOY	4	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	1.247725	1.247725	0.5240445	0.420	1.000	0.420
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	9	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	10	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	6	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.371	0.26	0.156	0.420	0.701	0.600
34	SV	SAC	194	SACRAMENTO POWER AUTHORITY	2	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	2.434594643	1.70421625	1.02252975	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	13	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	8	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
15	SJV	SJU	3523	ELK HILLS POWER LLC	3	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	2.457142637	1.719999846	1.031999908	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	12	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	7	7	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.28	0.28	0.168	0.600	1.000	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	16	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
36	MD	MOJ	104701849	HIGH DESERT POWER PROJECT	14	1	COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.412	0.288365	0.173	0.420	0.700	0.600
57	SV	YS	257	WOODLAND BIOMASS POWER LTD	20	1	COOLING TOWER - CIRCULATION RATE	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.014285714	0.01	0.006	0.420	0.700	0.600
19	SC	SC	11034	TRIGEN-LA ENERGY CORP	16	1	DISTRICT HEATING AND COOLING	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	7.12	4.984	2.9904	0.420	0.700	0.600
19	SC	SC	9053	TRIGEN- LA ENERGY CORP	20	1	DISTRICT HEATING AND COOLING	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	1.23	0.861	0.5166	0.420	0.700	0.600
30	SC	SC	9217	TRIGEN-LA ENERGY CORP	3	1	DISTRICT HEATING AND COOLING	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.32	0.224	0.1344	0.420	0.700	0.600
36	MD	MOJ	104801880	RRI ENERGY COOLWATER, LLC.	90011	1	DRIFT CT UNIT 1	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.5997	0.5997	0.5997	1.000	1.000	1.000
36	MD	MOJ	104801880	RRI ENERGY COOLWATER, LLC.	90012	1	DRIFT CT UNIT 2	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.5997	0.5997	0.5997	1.000	1.000	1.000
36	MD	MOJ	104801880	RRI ENERGY COOLWATER, LLC.	90013	1	DRIFT CT UNIT 3	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	6.668	6.668	6.668	1.000	1.000	1.000
36	MD	MOJ	104801880	RRI ENERGY COOLWATER, LLC.	90014	1	DRIFT CT UNIT 4	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	6.668	6.668	6.668	1.000	1.000	1.000
33	SC	SC	68042	CORONA ENERGY PARTNERS, LTD	2	1	ELECTIC POWER AND STEAM COGENERATION FACILITY	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	5.45	3.815	2.289	0.420	0.700	0.600
19	SC	SC	51620	WHEELABRATOR NORWALK ENERGY CO INC	13	1	ELECTRIC POWER GENERATING FACILITY	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	3.16	2.212	1.3272	0.420	0.700	0.600
36	SC	SC	115315	RRI ENERGY ETIWANDA, INC.	1	1	ELECTRIC POWER GENERATION	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	114.16	79.912	47.9472	0.420	0.700	0.600
19	SC	SC	128243	BURBANK CITY,BURBANK WATER & POWER,SCPPA	1	1	ELECTRIC POWER GENERATION	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	1.24	0.868	0.5208	0.420	0.700	0.600
19	SC	SC	25638	BURBANK CITY, BURBANK WATER & POWER	16	1	ELECTRICAL UTILITY POWER PRODUCTION	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	4.15	2.905	1.743	0.420	0.700	0.600
27	NCC	MBU	220	CALPINE KING CITY COGEN, LLC	6	1	PEAKER COOLING TOWER	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.36	0.252	0.1512	0.420	0.700	0.600
19	SC	SC	14502	VERNON CITY, LIGHT & POWER DEPT	1	1	POWER GENERATION	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.85	0.595	0.357	0.420	0.700	0.600
19	SC	SC	800170	LA CITY, DWP HARBOR GENERATING STATION	7	1	POWER PLANT	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.05	0.035	0.021	0.420	0.700	0.600
19	SC	SC	800170	LA CITY, DWP HARBOR GENERATING STATION	5	1	POWER PLANT	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.07	0.049	0.0294	0.420	0.700	0.600
19	SC	SC	800170	LA CITY, DWP HARBOR GENERATING STATION	4	1	POWER PLANT	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.09	0.063	0.0378	0.420	0.700	0.600
19	SC	SC	800193	LA CITY, DWP VALLEY GENERATING STATION	6	1	POWER PLANT	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.04	0.028	0.0168	0.420	0.700	0.600
19	SC	SC	800170	LA CITY, DWP HARBOR GENERATING STATION	6	1	POWER PLANT	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	0.06	0.042	0.0252	0.420	0.700	0.600
19	SC	SC	800075	LA CITY, DWP SCATTERGOOD GENERATING STN	37	1	POWER PLANT	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	13.01	9.107	5.4642	0.420	0.700	0.600
19	SC	SC	800193	LA CITY, DWP VALLEY GENERATING STATION	7	1	POWER PLANT	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	2.25	1.575	0.945	0.420	0.700	0.600
19	SC	SC	800193	LA CITY, DWP VALLEY GENERATING STATION	8	1	POWER PLANT	38500101	COOLING TOWER	PROCESS COOLING	MECHANICAL DRAFT	9.7	6.79	4.074	0.420	0.700	0.600
														average	**0.478**	**0.742**	**0.633**

Calculated PM10 and PM2.5 Cooling Tower Emission Factors as a Function of Recirculating Water TDS (Michelleti)

Recirculating Water TDS (ppm)	Maximum Drift Droplet Diameter for PM_{10} Particlates (µm)	Maximum Drift Droplet Diameter for $PM_{2.5}$ Particlates (µm)	Percent Particulate Emissions > 10 µm	Percent Particulate Emissions > 2.5 µm
500	168	41	68%	86%
1000	133	33	73%	88%
2500	86	24	78%	89%
5000	78	19	81%	90%
10000	63	14	83%	90%
20000	49	12	85%	91%
30000	41	11	86%	91%

Notes:

[1] Assumes spherical particulate matter having a density of 2.36 gm/cm3 and 0.002% drift rate.

BACKGROUND

The cooling tower emission estimate uses what staff believes to be an inappropriate assumption that may underestimate the potential PM2.5 (particulate matter) emissions from the cooling towers. The Applicant uses a factor from a South Coast Air Quality Management District (SCAQMD) website table that indicates only 60 percent of the cooling tower PM10 emissions are PM2.5. This table value assumption comes from the Air Resources Board (ARB) CEIDARS (data base) "unspecified" category that clearly is not specific to cooling towers and has not been technically justified for cooling tower use. Staff believes that, unless the applicant can provide technically justified rationale to lower PM2.5 emissions, it should be conservatively assumed that all particulate from cooling tower drift is PM10 and PM2.5. Staff needs the applicant to revise the cooling tower emission calculations.

DATA REQUEST

18. Please recalculate the cooling tower particulate emissions considering the mist eliminator drift guarantee of 0.0005 percent of recirculating water flow, and assuming that all particulate emissions are both PM10 and PM2.5.

RESPONSE

The factor listed in the SCAQMD guidance indicating that particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) is 60 percent of total particulate matter less than 10 microns in diameter (PM_{10}) (*Updated CEIDARS Table with $PM_{2.5}$ Fractions)* is specified for cooling tower operation and is not specifically mentioned as being based on an "unspecified" category. Table 18-1 is a copy of the SCAQMD table, presented for reference. Furthermore, the Applicant believes that 60 percent is a conservative overestimate of the $PM_{2.5}$ emissions from the cooling towers as discussed below. Therefore, the Applicant wishes to use the 60 percent factor.

In determining PM emissions from cooling towers, the HECA Project conservatively estimated the total PM_{10} emissions by assuming the full concentration of dissolved solids in any exiting water droplets will be converted to airborne PM_{10}, rather than using either the recommended factor provided by the SCAQMD website (PM_{10} emission from cooling towers is 70 percent of the total PM emissions) or the U.S. EPA's AP-42 guidance, which confirms that it is conservative to use the assumption that all dissolved solids in any exiting water droplets will be converted to airborne PM_{10}. Section 13.4.2 of AP-42 states:

> "a conservatively high PM_{10} emission factor can be obtained by multiplying the total liquid drift factor by the total dissolved solids (TDS) fraction in the circulating water and by assuming that, once the water evaporates, all remaining solid particles are within the PM_{10} size range."

Other studies on similar subjects have also suggested that PM_{10} estimates made with the AP-42 assumptions (all particulate emissions is PM_{10}) may exaggerate actual emission rates from cooling towers (Michelleti, 2006). The studies further confirm that the assumption of all particulate emissions is $PM_{2.5}$ is an exaggeration.

For the $PM_{2.5}$ emission estimate, the HECA Project used the CEIDARS factor provided by SCAQMD guidance ($PM_{2.5}$ is 60 percent of total PM_{10}). This assumption is nearly identical to the request to use 100 percent of the PM_{10} as $PM_{2.5}$ if only a 70 percent PM_{10} to total solids factor were used in the initial PM_{10} calculation. For example, if the total solids were calculated to be 10, the PM_{10} would be 7 using the SCAQMD factor, and the $PM_{2.5}$ would be 7 using the approach from this data request. This approach compares well to the $PM_{2.5}$ of 6 using the Applicant's approach. However, both of these approaches are overly conservative, and the Applicant believes that 60 percent is applicable based on the following discussion.

Table 18-1
Updated CEIDARS Table with $PM_{2.5}$ Fractions

Source Classification Code (SCC) Main Category	SCC Subcategory	$PM_{2.5}$ Fraction of Total PM	PM_{10} Fraction of Total PM	$PM_{2.5}$ Fraction of PM_{10}
Asbestos Removal		0.500	0.500	1.000
Asphalt Paving/ Roofing	Fugitive Emissions	0.925	0.960	0.964
	Manufacturing	0.945	0.980	0.964
Burning	Agriculture/Field Crops, Weed Abatement	0.938	0.984	0.954
	Forest Management, Timber and Brush Fire	0.854	0.961	0.889
	Orchard Prunings	0.925	0.981	0.943
	Range Management, Waste Burning	0.932	0.983	0.948
	Unplanned Structural Fires	0.914	0.980	0.933
Cement Manufacturing		0.620	0.920	0.674
Chemical Manufacturing	Fertilizer-Urea	0.950	0.960	0.990
	Organic and Inorganic Chemicals	0.890	0.900	0.989
Coatings, Solvents, Inks And Dyes	Solvent Based	0.925	0.960	0.964
	Water-Based Coating	0.620	0.680	0.912
Consumer Products		0.925	0.960	0.964
Cooking	Baking, Charbroiling, Deep Fat Frying	0.420	0.700	0.600
Cooling Tower		0.420	0.700	0.600
Dry Cleaning		0.925	0.960	0.964
Electroplating	Hexavalent Chrome, Cadmium	1.000	1.000	1.000
	Zinc and Copper	0.925	0.960	0.964
External Combustion	Coal, Coke, Lignite	0.150	0.400	0.375
	Gaseous Fuel-Except Petroleum and Industrial Process Heaters	1.000	1.000	1.000
	Gaseous Fuel – Petroleum and Industrial Process Heater Only	0.930	0.950	0.979
	Liquid Fuel – Except Residual Oil	0.967	0.976	0.991
	Residual Oil – Except Utility Boilers	0.760	0.870	0.874
	Residual Oil – Utility Boilers Only	0.953	0.970	0.982
	Steel Furnace	0.930	0.980	0.949
	Wood/Bark Waste	0.927	0.997	0.930

Table 18-1
Updated CEIDARS Table with $PM_{2.5}$ Fractions (Continued)

Source Classification Code (SCC) Main Category	SCC Subcategory	$PM_{2.5}$ Fraction of Total PM	PM_{10} Fraction of Total PM	$PM_{2.5}$ Fraction of PM_{10}
Fabricated Metals	Abrasive Blasting	0.790	0.860	0.919
	Arc Welding, Oxy Fuel, Copper, Zinc, Bath	0.925	0.960	0.964
Food and Agriculture	Coffee Roasting	0.610	0.620	0.984
	Fermentation, Rendering, Fish and Nut Processing	0.420	0.700	0.600
	Grain Elevators	0.010	0.290	0.034
	Grain Milling, Drying	0.400	0.540	0.741
	Livestock Waste	0.420	0.700	0.600
Fugitive Dust	Agricultural Tilling Dust	0.101	0.454	0.222
	Construction and Demolition	0.102	0.489	0.208
	Landfill Dust	0.102	0.489	0.208
	Livestock Dust	0.055	0.482	0.114
	Paved Road Dust	0.077	0.457	0.169
	Unpaved Road Dust	0.126	0.594	0.212
Fugitive Emissions – Organic and Inorganic	Liquid Fuel Storage/Handling, Loading, Unloading Dispensing	0.925	0.960	0.964
	Natural Gas Production, Crude Oil Production, Petroleum Refining	0.555	0.610	0.910
	Organic and Inorganic Chemcals	0.925	0.960	0.964
	Processing	0.925	0.960	0.964
	Well Cellears, Pumps, Valves, Flages, Seals	0.925	0.960	0.964

Notes:

PM = particulate matter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
PM_{10} = particulate matter less than 10 microns in diameter
SCC = Source Classification Code

A U.S. EPA report provided a calculated estimate on the effect of evaporation on droplet size, which presented an equivalent PM size generation as a function of droplet size (U.S. EPA, 1998) (see Figure 18-1 and Attachment 18-1).

Using manufacturer-provided data on mass distribution of drift droplet size for cooling tower drift dispersed from Marley TU10 and TU12 Excel Drift Eliminators, particulate emissions from the HECA Project cooling towers can be calculated as shown in Table 18-2.

Figure 18-1
Particle Size as Function of Droplet Size

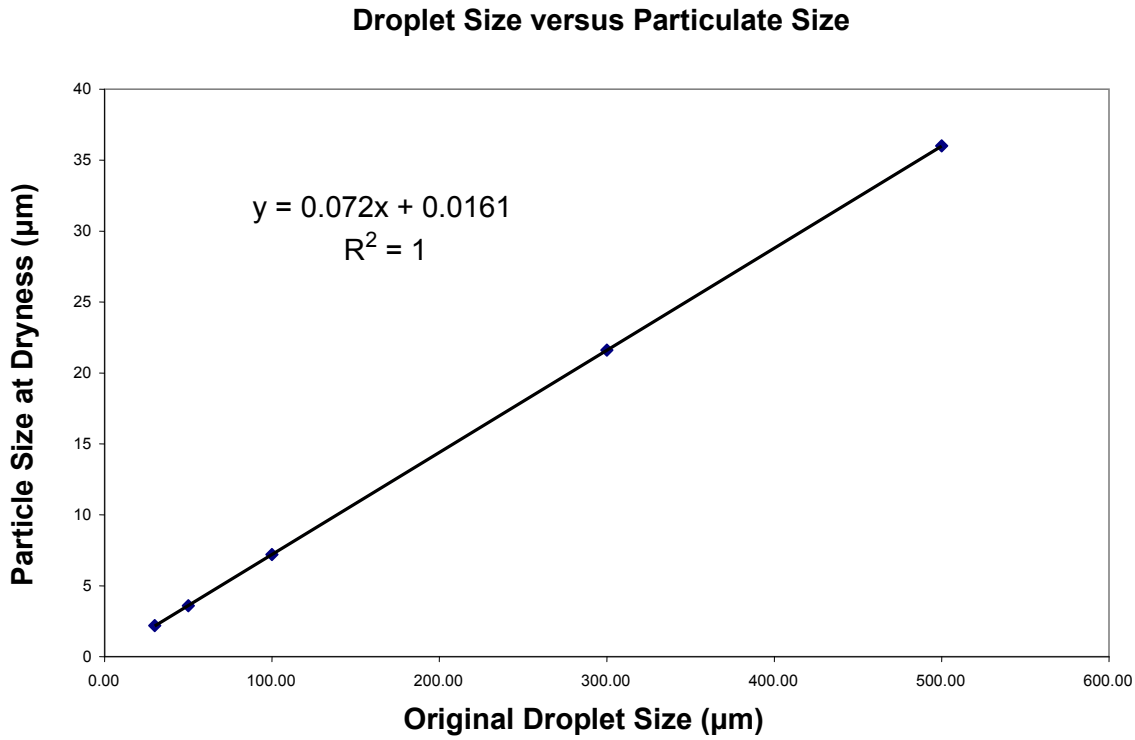


Table 18-2
Cooling Tower Droplet Mass Distribution (U.S. EPA)

Droplet Size (Microns)[1]	Mass Fraction[1]	PM Diameter (Microns)[2]
525	0.2%	37.82
375	1.0%	27.02
230	5.0%	16.58
170	10.0%	12.26
115	20.0%	8.30
65	40.0%	4.70
35	60.0%	2.54
15	80.0%	1.10
10	88.0%	0.74

Notes:

[1] Data provided by Marley for Marley TU10 and TU12 Excel Drift Eliminators. Mass Fraction specifies the fraction of particle with diameter larger than the specified diameter—0.2 percent of the drift will have particle sizes larger than 525 microns.

[2] Correlating particle size at dryness based on the data provided in EPA-450/3-87-010a.

A plot of particle distribution based on the last column of Table 18-2 is shown in Figure 18-2.

As shown in Figure 18-2, $PM_{2.5}$ emissions from cooling tower drift using the U.S. EPA methodology are approximately 40 percent of the total particulate emissions. Figure 18-2 shows that the HECA Project's assumption that $PM_{2.5}$ emissions are 60 percent of the PM_{10} (which was assumed as 100 percent particulates) is indeed conservative.

Another approach to estimating fine particulate emissions from cooling towers based on a representative drift droplet size distribution and TDS in the water was also commonly used (Aull, 1999). This approach was presented at the 94th Annual Air & Waste Management Association's Annual Meeting (June 2001) and presented in the State Water Resources Control Board's Draft Substitute Environmental Document on the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling as an alternative approach to better estimate fine particulate emissions from cooling towers (Reisman, 2001). By assuming that, shortly after being emitted into ambient air, each water droplet was to evaporate into a single, solid, spherical salt (sodium chloride) particle, particulate emissions from the HECA Project cooling towers can be calculated as shown in Table 18-3.

A plot of the last column in Table 18-3 is shown in Figure 18-3.

Using the second approach based on droplet size from the cooling tower manufacturer, and the approach by Aull (1999), $PM_{2.5}$ emissions from cooling towers is approximately 20 percent of the total particulate emission. This approach showed that the HECA Project's assumption that $PM_{2.5}$ emissions are 60 percent of the PM_{10} (which was assumed as 100 percent particulates) is far more conservative than the expected value.

Figure 18-2
Particulate Mass Distribution Curve (U.S. EPA)

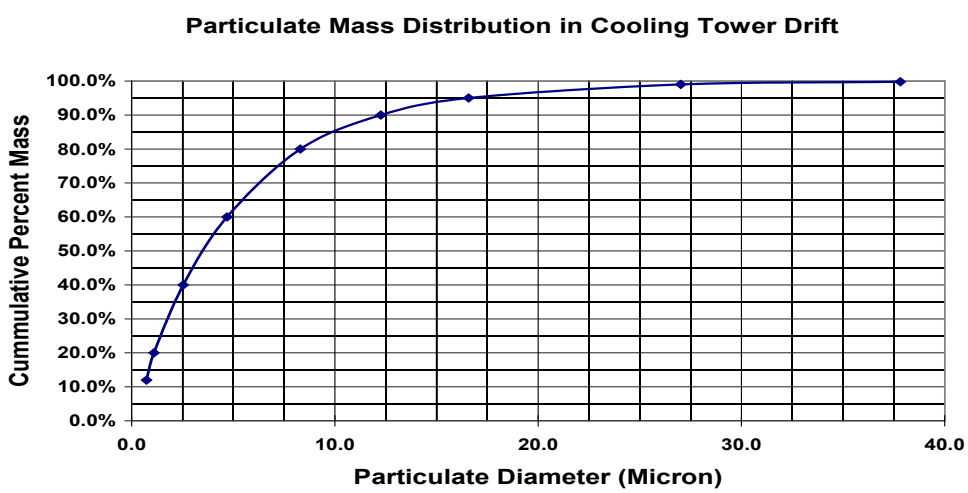


Table 18-3
Cooling Tower Droplet Mass Distribution[1]

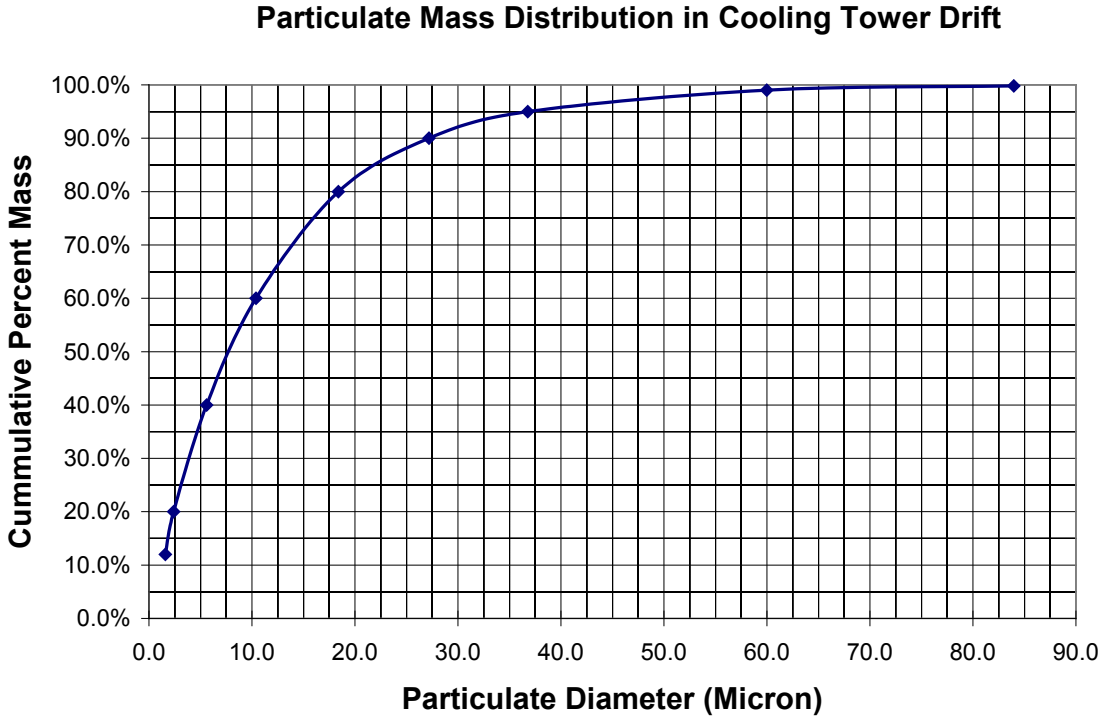
Droplet Size (Microns)[2]	Mass Fraction[2]	PM Diameter (Microns)[1]
525	0.2%	83.97
375	1.0%	59.98
230	5.0%	36.78
170	10.0%	27.19
115	20.0%	18.39
65	40.0%	10.40
35	60.0%	5.60
15	80.0%	2.40
10	88.0%	1.60

Notes:

[1] Correlating particle size at dryness based on the assumption that, shortly after being emitted into ambient air, each water droplet was to evaporate into a single, solid, spherical salt (sodium chloride) particle.

[2] Data provided by Marley for Marley TU10 and TU12 Excel Drift Eliminators. Mass Fraction specifies the fraction of particle with diameter larger than the specified diameter—0.2 percent of the drift will have particle sizes larger than 525 microns.

Figure 18-3 Particulate Mass Distribution Curve



References

Aull, R., 1999. Memorandum from R. Aull, Brentwood Industries, to J. Reisman, Greystone. December 7.

Michelleti, W.C., 2006. "Atmospheric Emissions from Power Plant Cooling Towers." CTI Journal. Vol. 27, No. 1.

Reisman, Joel, and Gordon Frisbie. Calculating Realistic PM_{10} Emissions from Cooling Towers. Greystone Environmental Consultants. *Environmental Progress,* Volume 21, Issue 2.

U.S. EPA, 1998. Chromium Estimate from Comfort Cooling Towers/Background Information for Proposed Standards. Emission Standards Division. EPA-450/3-87-010a.

ATTACHMENT 18-1

TABLE 3-4. EFFECT OF EVAPORATION ON DROPLET SIZE

Original droplet size, µm (mils)	Particle size at dryness, µm (mils)[a]	Droplet size, µm (mils)[b] 80 percent relative humidity	Droplet size, µm (mils)[b] 90 percent relative humidity	Solids concentration, ppm[a] 80 percent relative humidity
500 (19.69)	36.0 (1.4)	499.3 (19.66)	499.7 (19.67)	1,004
300 (11.81)	21.6 (0.85)	298.9 (11.77)	299.5 (11.79)	1,007
100 (3.94)	7.2 (0.28)	96.6 (3.80)	98.4 (3.87)	1,109
50 (1.97)	3.6 (0.14)	42.7 (1.68)	46.7 (1.84)	1,605
30 (1.2)	2.2 (0.09)	15.0 (0.59)	24.2 (0.95)	8,000

[a]Assumes total dissolved solids content of droplets is 1,000 µg/ml ($0.0624\ lb/ft^3$) and that the dissolved solids are primarily calcium carbonate (35 percent), magnesium carbonate (48 percent), and sodium carbonate (17 percent). Also assumes that the specific gravity of resulting dry particulate is the same as the weighted average of the specific gravity of the three major components.

[b]Assumes an evaporation time of 3 seconds and 26.7°C (80°F) dry bulb temperature. See Reference 29 for the equation used to calculate the droplet size.

29. Chemical Engineers' Handbook. 3rd Edition. John H. Perry, ed. New York, McGraw-Hill. 1950. p. 806.

Source: USEPA, 1998. Chromium Estimate from Comfort Cooling Towers- Background Information for Proposed Standards – Emission Standards Division. EPA-450/3-87-010a.

Appendix F

Toxic Air Contaminant Emissions

Hydrogen Energy California (HECA) Project
4/11/2012
Emissions Summary

Compound	CAS #	Annual Rate (TPY)	CTG/HRSG Stack (lb/yr)	Coal Dryer Stack (lb/yr)	Cooling Tower (Power Block) (lb/yr)	Cooling Tower (Process Area) (lb/yr)	Cooling Tower (ASU) (lb/yr)	Auxiliary Boiler (lb/yr)	Ammonia Plant Startup Heater (lb/yr)	Emergency Generators (lb/yr)	Fire Water Pump (lb/yr)	Gasification Flare (lb/yr)	SRU Flare (lb/yr)	Rectisol Flare (lb/yr)	TG Thermal Oxidizer (lb/yr)	CO_2 Vent (lb/yr)	Manufacturing Complex (lb/yr)	Onsite Truck (lb/yr)	Onsite Train (lb/yr)	Fugitives (lb/yr)
Acetaldehyde	75-07-0	2.15E-02	3.66E+01	6.46E+00																
Ammonia*	7664-41-7	1.57E+02	1.56E+05	2.75E+04				1.03E+03									1.18E+05			1.14E+04
Antimony	7440-36-0	1.32E-02	2.24E+01	3.95E+00																
Arsenic	7440-38-2	2.88E-02	4.88E+01	8.61E+00	5.33E-02	8.70E-02	2.40E-02	8.89E-02	1.47E-03			1.43E-02	7.75E-04	3.78E-03	2.13E-02					
Benzene	71-43-2	2.94E-02	4.88E+01	8.61E+00				9.33E-01	1.54E-02			1.50E-01	8.14E-03	3.97E-02	2.24E-01					
Beryllium	7440-41-7	3.11E-03	5.28E+00	9.33E-01				5.33E-03	8.80E-05			8.56E-04	4.65E-05	2.27E-04	1.28E-03					
Cadmium	7440-43-9	1.15E-01	1.95E+02	3.44E+01				4.89E-01	8.07E-03			7.85E-02	4.26E-03	2.08E-02	1.17E-01					
Carbon Disulfide	75-15-0	5.50E-01	9.35E+02	1.65E+02																
Carbonyl Sulfide	463-58-1	2.69E+00														5.32E+03				5.94E+01
Chromium	7440-47-3	6.55E-03	1.04E+01	1.83E+00				6.22E-01	1.03E-02			9.99E-02	5.42E-03	2.64E-02	1.49E-01					
Chromium (hexavalent)	18540-29-9	1.83E-03	3.11E+00	5.49E-01																
Cobalt	7440-48-4	3.14E-03	5.28E+00	9.33E-01				3.73E-02	6.16E-04			5.99E-03	3.25E-04	1.59E-03	8.95E-03					
Copper*	7440-50-8	2.93E-04			1.03E-02	1.69E-02	4.66E-03	3.78E-01	6.23E-03			6.06E-02	3.29E-03	1.61E-02	9.06E-02					
Cyanides	57-12-5	6.87E-02	1.16E+02	2.04E+01																1.15E+00
Fluoride*	1101	1.44E-03			9.31E-01	1.52E+00	4.20E-01													
Formaldehyde	50-00-0	2.28E-01	3.46E+02	6.10E+01				3.33E+01	5.50E-01			5.35E+00	2.91E-01	1.42E+00	7.99E+00					
Hexane	110-54-3	5.87E-01						8.00E+02	1.32E+01			1.28E+02	6.97E+00	3.40E+01	1.92E+02					
Hydrochloric Acid	7647-01-0	1.55E-01	2.64E+02	4.66E+01																
Hydrogen Fluoride (hydrofluoric acid)	7664-39-3	5.98E-01	1.02E+03	1.79E+02																
Hydrogen Sulfide	7783-06-4	2.64E+00														3.01E+03				2.28E+03
Lead	7439-92-1	6.70E-03	1.14E+01	2.01E+00																
Manganese	7439-96-5	1.67E-02	2.11E+01	3.73E+00	2.66E+00	4.35E+00	1.20E+00	1.69E-01	2.79E-03			2.71E-02	1.47E-03	7.18E-03	4.05E-02					
Mercury	7439-97-6	7.71E-03	1.03E+01	4.98E+00				1.16E-01	1.91E-03			1.85E-02	1.01E-03	4.91E-03	2.77E-02					
Methanol	67-56-1	7.09E+00																		1.42E+04
Methyl Bromide (Bromomethane)	74-83-9	5.70E-01	9.70E+02	1.71E+02																
Methylene Chloride (Dichloromethane)	75-09-2	2.63E-02	4.47E+01	7.89E+00																
Naphthalene	91-20-3	3.01E-02	5.08E+01	8.97E+00				2.71E-01	4.47E-03			4.35E-02	2.36E-03	1.15E-02	6.50E-02					
Nickel	7440-02-0	5.35E-03	7.93E+00	1.40E+00				9.33E-01	1.54E-02			1.50E-01	8.14E-03	3.97E-02	2.24E-01					
Nitric Acid*	7697-37-2	8.19E-01																		1.64E+03
Phenol	108-95-2	4.40E-01	7.48E+02	1.32E+02																
Propylene*	115-07-1	6.33E+00																		1.27E+04
Selenium	7782-49-2	6.77E-03	1.14E+01	2.01E+00	4.43E-02	7.23E-02	2.00E-02	1.07E-02	1.76E-04			1.71E-03	9.30E-05	4.53E-04	2.56E-03					
Sulfuric Acid and Sulfates*	7664-93-9	1.14E+00	1.93E+03	3.41E+02																
Toluene	108-88-3	1.50E-03	6.71E-01	1.18E-01				1.51E+00	2.49E-02			2.43E-01	1.32E-02	6.42E-02	3.62E-01					
Vanadium*	7440-62-2	7.50E-04						1.02E+00	1.69E-02			1.64E-01	8.91E-03	4.34E-02	2.45E-01					
Diesel Particulate Matter*	DPM	7.72E-02								4.51E+01	1.84E+00							1.48E+01	9.26E+01	
2-Methylnaphthalene	91-57-6	7.83E-06						1.07E-02	1.76E-04			1.71E-03	9.30E-05	4.53E-04	2.56E-03					
3-Methylchloranthrene	56-49-5	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
7,12-Dimethylbenz(a)anthracene	57-97-6	5.22E-06						7.11E-03	1.17E-04			1.14E-03	6.20E-05	3.02E-04	1.71E-03					
Acenaphthene	83-32-9	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Acenaphthylene	208-96-8	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Anthracene	120-12-7	7.83E-07						1.07E-03	1.76E-05			1.71E-04	9.30E-06	4.53E-05	2.56E-04					
Benz(a)anthracene	56-55-3	2.81E-05	4.68E-02	8.25E-03				8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Benzo(a)pyrene	50-32-8	3.91E-07						5.33E-04	8.80E-06			8.56E-05	4.65E-06	2.27E-05	1.28E-04					
Benzo(b)fluoranthene	205-99-2	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Benzo(g,h,i)perylene	191-24-2	3.91E-07						5.33E-04	8.80E-06			8.56E-05	4.65E-06	2.27E-05	1.28E-04					
Benzo(k)fluoranthene	207-08-9	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Chrysene	218-01-9	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Dibenzo(a,h)anthracene	53-70-3	3.91E-07						5.33E-04	8.80E-06			8.56E-05	4.65E-06	2.27E-05	1.28E-04					
Dichlorobenzene	106-46-7	3.91E-04						5.33E-01	8.80E-03			8.56E-02	4.65E-03	2.27E-02	1.28E-01					
Fluoranthene	206-44-0	9.78E-07						1.33E-03	2.20E-05			2.14E-04	1.16E-05	5.67E-05	3.20E-04					
Fluorene	86-73-7	9.13E-07						1.24E-03	2.05E-05			2.00E-04	1.08E-05	5.29E-05	2.98E-04					
Indeno(1,2,3-cd)pyrene	193-39-5	5.87E-07						8.00E-04	1.32E-05			1.28E-04	6.97E-06	3.40E-05	1.92E-04					
Phenanathrene	85-01-8	5.54E-06						7.55E-03	1.25E-04			1.21E-03	6.59E-05	3.21E-04	1.81E-03					
Pyrene	129-00-0	1.63E-06						2.22E-03	3.67E-05			3.57E-04	1.94E-05	9.44E-05	5.33E-04					
Total Combined HAPs and TACs (tpy)		**181.47**	**81.44**	**14.37**	**0.00**	**0.00**	**0.00**	**0.93**	**0.01**	**0.02**	**0.00**	**0.07**	**0.00**	**0.02**	**0.10**	**4.17**	**59.17**	**0.01**	**0.05**	**2.11E+01**
Total HAPs* (tpy)		**15.94**	**2.46**	**0.44**	**0.00**	**0.00**	**0.00**	**0.42**	**0.01**	**0.00**	**0.00**	**0.07**	**0.00**	**0.02**	**0.10**	**4.17**	**0.00**	**0.00**	**0.00**	**8.25E+00**

Note:
* Denotes pollutants that are not listed as Federal HAPs. These pollutants are not included in the HAP total provided. As shown, combined annual HAP emissions are less than 25 tons per year. Additionally, individual HAP emissions are below 10 tons per year.

Hydrogen Energy California LLC *4/11/2012*
Hydrogen Energy California (HECA) Project

Annual emissions based on 100 percent load at annual average temperature (65°F)

CT Fuel Input (Yearly Average - 65°F)=	2,537	10^6 Btu/hr (higher heating value)
Duct Burner Heat Input (Yearly Average - 65°F)=	290	10^6 Btu/hr (higher heating value)
Total HRSG Heat Input (Yearly Average - 65°F)=	2,827	10^6 Btu/hr (higher heating value)

Hourly emissions based on 100 percent load at average high ambient temperature (97°F)

CT Fuel Input (Avg. High Ambient - 97°F) =	2,583	10^6 Btu/hr (higher heating value)
Duct Burner Heat Input (97°F) =	278	10^6 Btu/hr (higher heating value)
Total HRSG Heat Input (97°F) =	2,861	10^6 Btu/hr (higher heating value)

HRSG		
HRSG (Firing Syngas) Normal Operating Hours =	8000	hr/yr
HRSG (Firing Natural Gas) Normal Operating Hours =	336	hr/yr
HRSG Startup Hours =	105	hr/yr
HRSG Shutdown Hours =	18	hr/yr
Total HRSG Operating Hours	**8,459**	**hr/yr**

Coal Dryer		
Coal Dryer Normal Operating Hours =	8000	hr/yr
Coal Dryer Startup Hours =	102	hr/yr
Coal Dryer Shutdown Hours =	8	hr/yr
Total Coal Dryer Operating Hours	**8,110**	**hr/yr**

Exhaust from HRSG normal operation would be splitted into	**85%**	**to HRSG stack**
	15%	**to coal dryer stack**

			HRSG + Coal Dryer					
			Toal Hourly Combined Emission	**Total Annual Combined Emissions**	**CTG/HRSG Stack**		**Coal Dryer Stack**	
Compound	**CAS #**	**Emission Factor** ($lb/10^{12}$ Btu coal)	**Hourly** (lb/hr)	**Annual** (lb/yr)	**Hourly** (lb/hr)	**Annual** (lb/yr)	**Hourly** (lb/hr)	**Annual** (lb/yr)
Acetaldehyde	75-07-0	1.8	5.15E-03	4.30E+01	4.38E-03	3.66E+01	7.72E-04	6.46E+00
Ammonia	7664-41-7	5 ppm	2.17E+01	1.84E+05	1.85E+01	1.56E+05	3.20E+00	2.75E+04
Antimony	7440-36-0	1.1	3.15E-03	2.63E+01	2.68E-03	2.24E+01	4.72E-04	3.95E+00
Arsenic	7440-38-2	2.4	6.87E-03	5.74E+01	5.84E-03	4.88E+01	1.03E-03	8.61E+00
Benz(a)anthracene	56-55-3	0.0023	6.58E-06	5.50E-02	5.59E-06	4.68E-02	9.87E-07	8.25E-03
Benzene	71-43-2	2.4	6.87E-03	5.74E+01	5.84E-03	4.88E+01	1.03E-03	8.61E+00
Beryllium	7440-41-7	0.26	7.44E-04	6.22E+00	6.32E-04	5.28E+00	1.12E-04	9.33E-01
Cadmium	7440-43-9	9.6	2.75E-02	2.30E+02	2.33E-02	1.95E+02	4.12E-03	3.44E+01
Carbon disulfide	75-15-0	46	1.32E-01	1.10E+03	1.12E-01	9.35E+02	1.97E-02	1.65E+02
Chromium (hexavalent)	18540-29-9	0.15	4.38E-04	3.66E+00	3.72E-04	3.11E+00	6.57E-05	5.49E-01
Chromium	7440-47-3	0.51	1.46E-03	1.22E+01	1.24E-03	1.04E+01	2.19E-04	1.83E+00
Cobalt	7440-48-4	0.26	7.44E-04	6.22E+00	6.32E-04	5.28E+00	1.12E-04	9.33E-01
Cyanides	57-12-5	5.7	1.63E-02	1.36E+02	1.39E-02	1.16E+02	2.45E-03	2.04E+01
Formaldehyde	50-00-0	17	4.86E-02	4.07E+02	4.13E-02	3.46E+02	7.30E-03	6.10E+01
Hydrochloric acid	7647-01-0	13	3.72E-02	3.11E+02	3.16E-02	2.64E+02	5.58E-03	4.66E+01
Hydrogen fluoride (Hydrofluoric acid)	7664-39-3	50	1.43E-01	1.20E+03	1.22E-01	1.02E+03	2.15E-02	1.79E+02
Lead	7439-92-1	0.56	1.60E-03	1.34E+01	1.36E-03	1.14E+01	2.40E-04	2.01E+00
Manganese	7439-96-5	1.0	2.98E-03	2.49E+01	2.53E-03	2.11E+01	4.46E-04	3.73E+00
Mercury	7439-97-6	see notes	1.83E-03	1.53E+01	1.21E-03	1.03E+01	6.14E-04	4.98E+00
Methyl bromide (Bromomethane)	74-83-9	47.7	1.36E-01	1.14E+03	1.16E-01	9.70E+02	2.05E-02	1.71E+02
Methylene chloride (Dichloromethane)	75-09-2	2.2	6.29E-03	5.26E+01	5.35E-03	4.47E+01	9.44E-04	7.89E+00
Naphthalene	91-20-3	2.5	7.15E-03	5.98E+01	6.08E-03	5.08E+01	1.07E-03	8.97E+00
Nickel	7440-02-0	0.39	1.12E-03	9.33E+00	9.48E-04	7.93E+00	1.67E-04	1.40E+00
Phenol	108-95-2	36.8	1.05E-01	8.80E+02	8.95E-02	7.48E+02	1.58E-02	1.32E+02
Selenium	7782-49-2	0.56	1.60E-03	1.34E+01	1.36E-03	1.14E+01	2.40E-04	2.01E+00
Sulfuric acid and sulfates	7664-93-9	95	2.72E-01	2.27E+03	2.31E-01	1.93E+03	4.08E-02	3.41E+02
Toluene	108-88-3	0.033	9.44E-05	7.89E-01	8.03E-05	6.71E-01	1.42E-05	1.18E-01

Notes:

1) For the normal operating scenario, the unit will primarily fire syngas with natural gas as a backup fuel.
2) Emission factors are taken from Wabash River test data and the National Energy Technology Laboratory, U.S. Dept of Energy, Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report, December 2002.
3) Ammonia slip from the SCR (5 parts per million volume dry @ 15 percent O_2) - provided by Fluor - see Criteria Pollutant emission spreadsheet for details.
4) Btu = British thermal units.
5) Mercury (Hg) emission estimates are based on the following assumptions:

Total gasifier coal feed rate	4850	stpd	
Hg concentration in coal feed	0.09	ppmw	
Total Hg in coal feed	0.873	lb/day	= 0.09 lb Hg/10^6 lb coal x 2000 lb/ton
Uncontrolled coal dryer Hg emission (5.5% of feed) from volatilization	0.048	lb/day	
Coal dryer Hg emissions control efficiency	80%		
Controlled coal dryer Hg emission from volatilization	0.0096	lb/day	
Total Controlled coal dryer Hg emission from volatilization + HRSG flue gas	0.0147	lb/day	
Hg in syngas from gasifier	0.863	lb/day	
Control efficiency of the mercury cleanup in the syngas	96%		
Controlled HG emissions in HRSG flue gas	0.034	lb/day	
Controlled HG emissions from the HRSG stack	0.029	lb/day	

6) The emission rates of natural gas firing (startup, shutdown, and 336 hours of steady state operation) were calculated based on the emission factors used for the syngas firing.
7) Approximiately 15% of the HRSG exhaust is directed to the coal dryer where is passes over pulverized coal to dry it before it is injected into the gasifier. Therefore, it was assumed that HRSG/coal dryer exhaust is split based on 85%/15%. No exhaust will be directed to the coal dryer during natural gas operations or portions of startup and shutdown.
8) Annual emissions for both HRSG and coal dryer based on the higher hours of operation of the HRSG

Hydrogen Energy California LLC *4/11/2012*
Hydrogen Energy California (HECA) Project

Cooling Tower Operating Parameters

	Power Block	Process Area	ASU
Cooling water (CW) circulation rate, gpm =	95,500	162,582	44,876
CW circulation rate (million lb/hr) =	48	81	22
CW dissolved solids (ppmw) =	9,000	9,000	2,000
Drift, fraction of circulating CW =	0.0005%	0.0005%	0.0005%
Cooling Tower Operating Hours	8,668	8,314	8,314
Number of cells in tower	12	13	4

Assumed maximum TDS in circulating cooling water, normally TDS will be less.

Power Block Cooling Tower

Compound	CAS # / OEHHA reference #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)	Hourly per Cell (lb/hr)	Annual per Cell (lb/yr)
Arsenic	7440-38-2	0.026	6.15E-06	5.33E-02	5.12E-07	4.44E-03
Copper	7440-50-8	0.005	1.19E-06	1.03E-02	9.95E-08	8.62E-04
Fluoride	1101	0.45	1.07E-04	9.31E-01	8.95E-06	7.76E-02
Manganese	7439-96-5	1.29	3.07E-04	2.66E+00	2.56E-05	2.22E-01
Selenium	7784-49-2	0.02	5.11E-06	4.43E-02	4.26E-07	3.69E-03

Notes:

1) The emissions are based on the concentrations of each constituent found in the raw cooling water analysis, cycles of concentration, and drift rate.
2) Arsenic ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).
3) Copper ppm value shown is one-half of stated detection limit.
4) Fluoride ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).
5) Manganese ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).
6) Selenium ppm value shown taken as average of analytical test results (DWR).

Process Area Cooling Tower

Compound	CAS # / OEHHA reference #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)	Hourly per Cell (lb/hr)	Annual per Cell (lb/yr)
Arsenic	7440-38-2	0.026	1.05E-05	8.70E-02	8.05E-07	6.69E-03
Copper	7440-50-8	0.005	2.03E-06	1.69E-02	1.56E-07	1.30E-03
Fluoride	1101	0.45	1.83E-04	1.52E+00	1.41E-05	1.17E-01
Manganese	7439-96-5	1.29	5.23E-04	4.35E+00	4.02E-05	3.34E-01
Selenium	7784-49-2	0.02	8.70E-06	7.23E-02	6.69E-07	5.56E-03

Notes:

1) The emissions are based on the concentrations of each constituent found in the raw cooling water analysis, cycles of concentration, and drift rate.
2) Arsenic ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).
3) Copper ppm value shown is one-half of stated detection limit.
4) Fluoride ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).
5) Manganese ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).
6) Selenium ppm value shown taken as average of analytical test results (DWR).

ASU Cooling Tower

Compound	CAS # / OEHHA reference #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)	Hourly per Cell (lb/hr)	Annual per Cell (lb/yr)
Arsenic	7440-38-2	0.026	2.89E-06	2.40E-02	7.22E-07	6.00E-03
Copper	7440-50-8	0.005	5.61E-07	4.66E-03	1.40E-07	1.17E-03
Fluoride	1101	0.45	5.05E-05	4.20E-01	1.26E-05	1.05E-01
Manganese	7439-96-5	1.29	1.44E-04	1.20E+00	3.61E-05	3.00E-01
Selenium	7784-49-2	0.02	2.40E-06	2.00E-02	6.00E-07	4.99E-03

Notes:

1) The emissions are based on the concentrations of each constituent found in the raw cooling water analysis, cycles of concentration, and drift rate.
2) Arsenic ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).
3) Copper ppm value shown is one-half of stated detection limit.
4) Fluoride ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).
5) Manganese ppm value shown taken as average of analytical test results (Fruit Growers Laboratory).
6) Selenium ppm value shown taken as average of analytical test results (DWR).

Auxiliary Boiler — HAP Emissions Summary

Hydrogen Energy California LLC — *4/11/2012*

Hydrogen Energy California (HECA) Project

Operating Parameters

Auxiliary Boiler Heat Input =	213	10^6 Btu/hr (HHV)
Natural gas heating value =	1,050	Btu/scf
Fuel usage =	0.203	10^6 scf/hr
Auxiliary Boiler Operating Hours =	2,190	hours per year

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Hourly (lb/hr)	Annual (lb/yr)
Ammonia	7664-41-7	5 ppm	4.69E-01	1.03E+03
Arsenic	7440-38-2	2.00E-04	4.06E-05	8.89E-02
Benzene	71-43-2	2.10E-03	4.26E-04	9.33E-01
Beryllium	7440-41-7	1.20E-05	2.43E-06	5.33E-03
Cadmium	7440-43-9	1.10E-03	2.23E-04	4.89E-01
Chromium	7440-47-3	1.40E-03	2.84E-04	6.22E-01
Cobalt	7440-48-4	8.40E-05	1.70E-05	3.73E-02
Copper	7440-50-8	8.50E-04	1.72E-04	3.78E-01
Formaldehyde	50-00-0	7.50E-02	1.52E-02	3.33E+01
Hexane	110-54-3	1.80E+00	3.65E-01	8.00E+02
Manganese	7439-96-5	3.80E-04	7.71E-05	1.69E-01
Mercury	7439-97-6	2.60E-04	5.27E-05	1.16E-01
Naphthalene	91-20-3	6.10E-04	1.24E-04	2.71E-01
Nickel	7440-02-0	2.10E-03	4.26E-04	9.33E-01
Selenium	7782-49-2	2.40E-05	4.87E-06	1.07E-02
Toluene	108-88-3	3.40E-03	6.90E-04	1.51E+00
Vanadium	7440-62-2	2.30E-03	4.67E-04	1.02E+00
Benzo(a)pyrene	50-32-8	1.20E-06	2.43E-07	5.33E-04
Benz(a)anthracene	56-55-3	1.80E-06	3.65E-07	8.00E-04
Benzo(b)fluoranthene	205-99-2	1.80E-06	3.65E-07	8.00E-04
Chrysene	218-01-9	1.80E-06	3.65E-07	8.00E-04
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	2.43E-07	5.33E-04
Dichlorobenzene	106-46-7	1.20E-03	2.43E-04	5.33E-01
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	3.65E-07	8.00E-04
2-Methylnaphthalene	91-57-6	2.40E-05	4.87E-06	1.07E-02
3-Methylchloranthrene	56-49-5	1.80E-06	3.65E-07	8.00E-04
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	3.25E-06	7.11E-03
Acenaphthene	83-32-9	1.80E-06	3.65E-07	8.00E-04
Acenaphthylene	208-96-8	1.80E-06	3.65E-07	8.00E-04
Anthracene	120-12-7	2.40E-06	4.87E-07	1.07E-03
Benzo(g,h,i)perylene	191-24-2	1.20E-06	2.43E-07	5.33E-04
Benzo(k)fluoranthene	207-08-9	1.80E-06	3.65E-07	8.00E-04
Fluoranthene	206-44-0	3.00E-06	6.09E-07	1.33E-03
Fluorene	86-73-7	2.80E-06	5.68E-07	1.24E-03
Phenanathrene	85-01-8	1.70E-05	3.45E-06	7.55E-03
Pyrene	129-00-0	5.00E-06	1.01E-06	2.22E-03

Notes:

1) Emission factors (lb/106 scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

2) Ammonia slip from the SCR (5 parts per million volume dry @ 15 percent O_2) - provided by Fluor - see Criteria Pollutant emission spreadsheet for details.

Ammonia Plant Startup Heater — HAP Emissions Summary

Hydrogen Energy California LLC — *4/11/2012*
Hydrogen Energy California (HECA) Project

Operating Parameters

Heat Input =	55	10^6 Btu/hr (HHV)
Natural gas heating value =	1,050	Btu/scf
Fuel usage =	0.052	10^6 scf/hr
Operating Hours =	140	hours per year

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.05E-05	1.47E-03
Benzene	71-43-2	2.10E-03	1.10E-04	1.54E-02
Beryllium	7440-41-7	1.20E-05	6.29E-07	8.80E-05
Cadmium	7440-43-9	1.10E-03	5.76E-05	8.07E-03
Chromium	7440-47-3	1.40E-03	7.33E-05	1.03E-02
Cobalt	7440-48-4	8.40E-05	4.40E-06	6.16E-04
Copper	7440-50-8	8.50E-04	4.45E-05	6.23E-03
Formaldehyde	50-00-0	7.50E-02	3.93E-03	5.50E-01
Hexane	110-54-3	1.80E+00	9.43E-02	1.32E+01
Manganese	7439-96-5	3.80E-04	1.99E-05	2.79E-03
Mercury	7439-97-6	2.60E-04	1.36E-05	1.91E-03
Naphthalene	91-20-3	6.10E-04	3.20E-05	4.47E-03
Nickel	7440-02-0	2.10E-03	1.10E-04	1.54E-02
Selenium	7782-49-2	2.40E-05	1.26E-06	1.76E-04
Toluene	108-88-3	3.40E-03	1.78E-04	2.49E-02
Vanadium	7440-62-2	2.30E-03	1.20E-04	1.69E-02
Benzo(a)pyrene	50-32-8	1.20E-06	6.29E-08	8.80E-06
Benz(a)anthracene	56-55-3	1.80E-06	9.43E-08	1.32E-05
Benzo(b)fluoranthene	205-99-2	1.80E-06	9.43E-08	1.32E-05
Chrysene	218-01-9	1.80E-06	9.43E-08	1.32E-05
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	6.29E-08	8.80E-06
Dichlorobenzene	106-46-7	1.20E-03	6.29E-05	8.80E-03
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	9.43E-08	1.32E-05
2-Methylnaphthalene	91-57-6	2.40E-05	1.26E-06	1.76E-04
3-Methylchloranthrene	56-49-5	1.80E-06	9.43E-08	1.32E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	8.38E-07	1.17E-04
Acenaphthene	83-32-9	1.80E-06	9.43E-08	1.32E-05
Acenaphthylene	208-96-8	1.80E-06	9.43E-08	1.32E-05
Anthracene	120-12-7	2.40E-06	1.26E-07	1.76E-05
Benzo(g,h,i)perylene	191-24-2	1.20E-06	6.29E-08	8.80E-06
Benzo(k)fluoranthene	207-08-9	1.80E-06	9.43E-08	1.32E-05
Fluoranthene	206-44-0	3.00E-06	1.57E-07	2.20E-05
Fluorene	86-73-7	2.80E-06	1.47E-07	2.05E-05
Phenanathrene	85-01-8	1.70E-05	8.90E-07	1.25E-04
Pyrene	129-00-0	5.00E-06	2.62E-07	3.67E-05

Notes:

1) Emission factors (lb/106 scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

Gasification Flare — HAP Emissions Summary

Hydrogen Energy California LLC — *4/11/2012*
Hydrogen Energy California (HECA) Project

Operating Parameters

Reference HHV =	1,050	btu/scf

Gasification Flare - Normal Operating Emissions From Pilot

Total Hours of Pilot Operation =	8,760	hr/yr
Flare Pilot Fuel Use =	0.5	10^6 Btu/hr

Gasification Flare - Operating Emissions During Gasifier Startup and Shutdown

	10^6 Btu/yr	Hours per year
Total Flare SU/SD Operation =	70,528	28
Flaring NG-Firing Rate =	2,926	6
Wet Unshifted Gas-Firing Rate =	2,386	4
Dry Shifted Gas-Firing Rate =	2,413	18

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Emission Factor ($lb/10^6$ Btu)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.90E-07	5.57E-04	1.43E-02
Benzene	71-43-2	2.10E-03	2.00E-06	5.85E-03	1.50E-01
Beryllium	7440-41-7	1.20E-05	1.14E-08	3.34E-05	8.56E-04
Cadmium	7440-43-9	1.10E-03	1.05E-06	3.07E-03	7.85E-02
Chromium	7440-47-3	1.40E-03	1.33E-06	3.90E-03	9.99E-02
Cobalt	7440-48-4	8.40E-05	8.00E-08	2.34E-04	5.99E-03
Copper	7440-50-8	8.50E-04	8.10E-07	2.37E-03	6.06E-02
Formaldehyde	50-00-0	7.50E-02	7.14E-05	2.09E-01	5.35E+00
Hexane	110-54-3	1.80E+00	1.71E-03	5.02E+00	1.28E+02
Manganese	7439-96-5	3.80E-04	3.62E-07	1.06E-03	2.71E-02
Mercury	7439-97-6	2.60E-04	2.48E-07	7.25E-04	1.85E-02
Naphthalene	91-20-3	6.10E-04	5.81E-07	1.70E-03	4.35E-02
Nickel	7440-02-0	2.10E-03	2.00E-06	5.85E-03	1.50E-01
Selenium	7782-49-2	2.40E-05	2.29E-08	6.69E-05	1.71E-03
Toluene	108-88-3	3.40E-03	3.24E-06	9.48E-03	2.43E-01
Vanadium	7440-62-2	2.30E-03	2.19E-06	6.41E-03	1.64E-01
Benzo(a)pyrene	50-32-8	1.20E-06	1.14E-09	3.34E-06	8.56E-05
Benz(a)anthracene	56-55-3	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Chrysene	218-01-9	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	1.14E-09	3.34E-06	8.56E-05
Dichlorobenzene	106-46-7	1.20E-03	1.14E-06	3.34E-03	8.56E-02
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.71E-09	5.02E-06	1.28E-04
2-Methylnaphthalene	91-57-6	2.40E-05	2.29E-08	6.69E-05	1.71E-03
3-Methylchloranthrene	56-49-5	1.80E-06	1.71E-09	5.02E-06	1.28E-04
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.52E-08	4.46E-05	1.14E-03
Acenaphthene	83-32-9	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Acenaphthylene	208-96-8	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Anthracene	120-12-7	2.40E-06	2.29E-09	6.69E-06	1.71E-04
Benzo(g,h,i)perylene	191-24-2	1.20E-06	1.14E-09	3.34E-06	8.56E-05
Benzo(k)fluoranthene	207-08-9	1.80E-06	1.71E-09	5.02E-06	1.28E-04
Fluoranthene	206-44-0	3.00E-06	2.86E-09	8.36E-06	2.14E-04
Fluorene	86-73-7	2.80E-06	2.67E-09	7.80E-06	2.00E-04
Phenanathrene	85-01-8	1.70E-05	1.62E-08	4.74E-05	1.21E-03
Pyrene	129-00-0	5.00E-06	4.76E-09	1.39E-05	3.57E-04

Notes:

1) Annual operation assumes total pilot operation of 8,760 hr/yr and plus gasifier startup and shutdown.

2) Emission factors ($lb/10^6$ scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

Hydrogen Energy California LLC *4/11/2012*
Hydrogen Energy California (HECA) Project

Operating Parameters

Reference HHV =	1,050	btu/scf

SRU Flare - Normal Operating Emissions From Pilot

Total Hours of Pilot Operation =	8,760	hr/yr
Elevated Flare Pilot Fuel Use =	0.3	10^6 Btu/hr

SRU Flare - Operating Emissions During Gasifier Startup and Shutdown

Total Flare Operation During SU/SD =	40.0	hr/yr
Natural Gas Heat Rate (assist gas) =	36.0	10^6 Btu/hr

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Emission Factor ($lb/10^6$ Btu)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.90E-07	6.91E-06	7.75E-04
Benzene	71-43-2	2.10E-03	2.00E-06	7.26E-05	8.14E-03
Beryllium	7440-41-7	1.20E-05	1.14E-08	4.15E-07	4.65E-05
Cadmium	7440-43-9	1.10E-03	1.05E-06	3.80E-05	4.26E-03
Chromium	7440-47-3	1.40E-03	1.33E-06	4.84E-05	5.42E-03
Cobalt	7440-48-4	8.40E-05	8.00E-08	2.90E-06	3.25E-04
Copper	7440-50-8	8.50E-04	8.10E-07	2.94E-05	3.29E-03
Formaldehyde	50-00-0	7.50E-02	7.14E-05	2.59E-03	2.91E-01
Hexane	110-54-3	1.80E+00	1.71E-03	6.22E-02	6.97E+00
Manganese	7439-96-5	3.80E-04	3.62E-07	1.31E-05	1.47E-03
Mercury	7439-97-6	2.60E-04	2.48E-07	8.99E-06	1.01E-03
Naphthalene	91-20-3	6.10E-04	5.81E-07	2.11E-05	2.36E-03
Nickel	7440-02-0	2.10E-03	2.00E-06	7.26E-05	8.14E-03
Selenium	7782-49-2	2.40E-05	2.29E-08	8.30E-07	9.30E-05
Toluene	108-88-3	3.40E-03	3.24E-06	1.18E-04	1.32E-02
Vanadium	7440-62-2	2.30E-03	2.19E-06	7.95E-05	8.91E-03
Benzo(a)pyrene	50-32-8	1.20E-06	1.14E-09	4.15E-08	4.65E-06
Benz(a)anthracene	56-55-3	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Chrysene	218-01-9	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	1.14E-09	4.15E-08	4.65E-06
Dichlorobenzene	106-46-7	1.20E-03	1.14E-06	4.15E-05	4.65E-03
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.71E-09	6.22E-08	6.97E-06
2-Methylnaphthalene	91-57-6	2.40E-05	2.29E-08	8.30E-07	9.30E-05
3-Methylchloranthrene	56-49-5	1.80E-06	1.71E-09	6.22E-08	6.97E-06
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.52E-08	5.53E-07	6.20E-05
Acenaphthene	83-32-9	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Acenaphthylene	208-96-8	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Anthracene	120-12-7	2.40E-06	2.29E-09	8.30E-08	9.30E-06
Benzo(g,h,i)perylene	191-24-2	1.20E-06	1.14E-09	4.15E-08	4.65E-06
Benzo(k)fluoranthene	207-08-9	1.80E-06	1.71E-09	6.22E-08	6.97E-06
Fluoranthene	206-44-0	3.00E-06	2.86E-09	1.04E-07	1.16E-05
Fluorene	86-73-7	2.80E-06	2.67E-09	9.68E-08	1.08E-05
Phenanathrene	85-01-8	1.70E-05	1.62E-08	5.88E-07	6.59E-05
Pyrene	129-00-0	5.00E-06	4.76E-09	1.73E-07	1.94E-05

Notes:

1) Annual operation assumes total pilot operation of 8,760 hr/yr plus gasifier startup and shutdown with assist gas.

2) Emission factors ($lb/10^6$ scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

Rectisol Flare — HAP Emissions Summary

Hydrogen Energy California LLC — *4/11/2012*
Hydrogen Energy California (HECA) Project

Operating Parameters

Reference HHV =	1,050	btu/scf

Operating Parameters - Normal Operating Emissions From Pilot

Rectisol Flare Pilot Firing Rate =	0.3	MMBtu/hr
Annual Operating Hours =	8,760	hr/yr

Rectisol Flare - Operating Emissions During Rectisol Startup and Shutdown

Total Flare Operation During SU/SD =	40	hr/yr
Heat Rate of Vent Gas, HHV =	430	10^6 Btu/hr

Compound	CAS Number	Emission Factor ($lb/10^6$ scf)	Emission Factor (lb/MMBtu)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.90E-07	8.20E-05	3.78E-03
Benzene	71-43-2	2.10E-03	2.00E-06	8.61E-04	3.97E-02
Beryllium	7440-41-7	1.20E-05	1.14E-08	4.92E-06	2.27E-04
Cadmium	7440-43-9	1.10E-03	1.05E-06	4.51E-04	2.08E-02
Chromium	7440-47-3	1.40E-03	1.33E-06	5.74E-04	2.64E-02
Cobalt	7440-48-4	8.40E-05	8.00E-08	3.44E-05	1.59E-03
Copper	7440-50-8	8.50E-04	8.10E-07	3.48E-04	1.61E-02
Formaldehyde	50-00-0	7.50E-02	7.14E-05	3.07E-02	1.42E+00
Hexane	110-54-3	1.80E+00	1.71E-03	7.38E-01	3.40E+01
Manganese	7439-96-5	3.80E-04	3.62E-07	1.56E-04	7.18E-03
Mercury	7439-97-6	2.60E-04	2.48E-07	1.07E-04	4.91E-03
Naphthalene	91-20-3	6.10E-04	5.81E-07	2.50E-04	1.15E-02
Nickel	7440-02-0	2.10E-03	2.00E-06	8.61E-04	3.97E-02
Selenium	7782-49-2	2.40E-05	2.29E-08	9.84E-06	4.53E-04
Toluene	108-88-3	3.40E-03	3.24E-06	1.39E-03	6.42E-02
Vanadium	7440-62-2	2.30E-03	2.19E-06	9.43E-04	4.34E-02
Benzo(a)pyrene	50-32-8	1.20E-06	1.14E-09	4.92E-07	2.27E-05
Benz(a)anthracene	56-55-3	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Chrysene	218-01-9	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	1.14E-09	4.92E-07	2.27E-05
Dichlorobenzene	106-46-7	1.20E-03	1.14E-06	4.92E-04	2.27E-02
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.71E-09	7.38E-07	3.40E-05
2-Methylnaphthalene	91-57-6	2.40E-05	2.29E-08	9.84E-06	4.53E-04
3-Methylchloranthrene	56-49-5	1.80E-06	1.71E-09	7.38E-07	3.40E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.52E-08	6.56E-06	3.02E-04
Acenaphthene	83-32-9	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Acenaphthylene	208-96-8	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Anthracene	120-12-7	2.40E-06	2.29E-09	9.84E-07	4.53E-05
Benzo(g,h,i)perylene	191-24-2	1.20E-06	1.14E-09	4.92E-07	2.27E-05
Benzo(k)fluoranthene	207-08-9	1.80E-06	1.71E-09	7.38E-07	3.40E-05
Fluoranthene	206-44-0	3.00E-06	2.86E-09	1.23E-06	5.67E-05
Fluorene	86-73-7	2.80E-06	2.67E-09	1.15E-06	5.29E-05
Phenanathrene	85-01-8	1.70E-05	1.62E-08	6.97E-06	3.21E-04
Pyrene	129-00-0	5.00E-06	4.76E-09	2.05E-06	9.44E-05

Notes:

1) Annual operation assumes total pilot operation of 8,760 hr/yr plus rectisol startup and shutdown.
2) Emission factors ($lb/10^6$ scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

Tail Gas Thermal Oxidizer — HAP Emissions Summary

Hydrogen Energy California LLC — *4/11/2012*
Hydrogen Energy California (HECA) Project

Operating Parameters

Normal Operations		
Tail Gas Thermal Oxidizer Heat Input =	13	10^6 Btu/hr (HHV)
Natural gas heating value =	1,050	Btu/scf
Fuel usage =	0.012	10^6 scf/hr
Tail Gas Thermal Oxidizer Operating Hours =	8,314	hr/yr
Startup Operations		
Heat Input =	80	10^6 Btu/hr (HHV)
Fuel usage =	0.076	10^6 scf/hr
Startup Hours per year =	48	hr/yr

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.77E-05	2.13E-02
Benzene	71-43-2	2.10E-03	1.86E-04	2.24E-01
Beryllium	7440-41-7	1.20E-05	1.06E-06	1.28E-03
Cadmium	7440-43-9	1.10E-03	9.74E-05	1.17E-01
Chromium	7440-47-3	1.40E-03	1.24E-04	1.49E-01
Cobalt	7440-48-4	8.40E-05	7.44E-06	8.95E-03
Copper	7440-50-8	8.50E-04	7.53E-05	9.06E-02
Formaldehyde	50-00-0	7.50E-02	6.64E-03	7.99E+00
Hexane	110-54-3	1.80E+00	1.59E-01	1.92E+02
Manganese	7439-96-5	3.80E-04	3.37E-05	4.05E-02
Mercury	7439-97-6	2.60E-04	2.30E-05	2.77E-02
Naphthalene	91-20-3	6.10E-04	5.40E-05	6.50E-02
Nickel	7440-02-0	2.10E-03	1.86E-04	2.24E-01
Selenium	7782-49-2	2.40E-05	2.13E-06	2.56E-03
Toluene	108-88-3	3.40E-03	3.01E-04	3.62E-01
Vanadium	7440-62-2	2.30E-03	2.04E-04	2.45E-01
Benzo(a)pyrene	50-32-8	1.20E-06	1.06E-07	1.28E-04
Benz(a)anthracene	56-55-3	1.80E-06	1.59E-07	1.92E-04
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.59E-07	1.92E-04
Chrysene	218-01-9	1.80E-06	1.59E-07	1.92E-04
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	1.06E-07	1.28E-04
Dichlorobenzene	106-46-7	1.20E-03	1.06E-04	1.28E-01
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.59E-07	1.92E-04
2-Methylnaphthalene	91-57-6	2.40E-05	2.13E-06	2.56E-03
3-Methylchloranthrene	56-49-5	1.80E-06	1.59E-07	1.92E-04
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.42E-06	1.71E-03
Acenaphthene	83-32-9	1.80E-06	1.59E-07	1.92E-04
Acenaphthylene	208-96-8	1.80E-06	1.59E-07	1.92E-04
Anthracene	120-12-7	2.40E-06	2.13E-07	2.56E-04
Benzo(g,h,i)perylene	191-24-2	1.20E-06	1.06E-07	1.28E-04
Benzo(k)fluoranthene	207-08-9	1.80E-06	1.59E-07	1.92E-04
Fluoranthene	206-44-0	3.00E-06	2.66E-07	3.20E-04
Fluorene	86-73-7	2.80E-06	2.48E-07	2.98E-04
Phenanathrene	85-01-8	1.70E-05	1.51E-06	1.81E-03
Pyrene	129-00-0	5.00E-06	4.43E-07	5.33E-04

Notes:
1) Emission factors ($lb/10^6$ scf) are from EPA AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4.

Intermittent CO_2 Vent — HAP Emissions Summary

Hydrogen Energy California LLC — *4/11/2012*
Hydrogen Energy California (HECA) Project

Operating Parameters

Total Hours of Operation =	504	hr/yr
Total Flow =	761,400	lb/hr
Total Flow =	17,584	lbmol/hr
Molecular weight		
COS	60	lb/lbmol
H_2S	34	lb/lbmol

Compound	CAS #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)
Carbonyl Sulfide	463-58-1	10	1.06E+01	5.32E+03
Hydrogen Sulfide	7783-06-4	10	5.98E+00	3.01E+03

Notes:

1) Emission rates based on plant design and 504 hours per year of full venting.

Emergency Diesel Generator — HAP Emissions Summary

Hydrogen Energy California LLC — *4/11/2012*

Hydrogen Energy California (HECA) Project

Operating Parameters

Emergency Generator Specification =	2,922	Bhp
Emergency Generator Operating Hours =	50	hr/yr

PLEASE NOTE THAT THERE ARE TWO GENERATORS; EMISSION SHOWN IS FOR INDIVIDUAL GENERATORS.

Compound	CAS # /OEHHA reference #	Emission Factor (g/Bhp/hr)	Hourly (lb/hr)	Annual (lb/yr)
Diesel Particulate Matter	9901	0.07	4.51E-01	2.25E+01

Note:

1) Emission factor shown is based on U.S. EPA Tier 4 non-road diesel engine emissions standards.

2) Emission rate shown is for individual generator. There are two generators associated with the Project.

Emergency Diesel Firewater Pump — HAP Emissions Summary

Hydrogen Energy California LLC — *4/11/2012*

Hydrogen Energy California (HECA) Project

Operating Parameters

Fire Water Pump Specification =	556	Bhp
Fire Water Pump Operating Hours =	100	hr/yr

Compound	CAS # /OEHHA reference #	Emission Factor (g/Bhp/hr)	Hourly (lb/hr)	Annual (lb/yr)
Diesel Particulate Matter	9901	0.015	1.84E-02	1.84E+00

Note:

1) Emission factor shown is based on U.S. EPA Tier 4 non-road diesel engine emissions standards.

Urea HP Absorber

Urea HP Absorber Operating Hours = 8,052 hr/yr

Compound	CAS #	Hourly (lb/hr)	Annual (lb/yr)
Ammonia (NH3)	8013-59-0	11.14	89,675

Note:

1) Emission rate was estimated based on reference plant information. See criteria pollutant emission calculations. Annual operation includes hours for plant startup.

Urea LP Absorber

Urea LP Absorber Operating Hours = 8,052 hr/yr

Compound	CAS #	Hourly (lb/hr)	Annual (lb/yr)
Ammonia (NH3)	8013-59-0	2.02	16,305

Note:

1) Emission rate was estimated based on reference plant information. See criteria pollutant emission calculations. Annual operation includes hours for plant startup.

Urea Pastillation

Urea Pastillation Operating Hours = 8,052 hr/yr

Compound	CAS #	Hourly (lb/hr)	Annual (lb/yr)
Ammonia (NH3)	8013-59-0	1.02	8,224

Note:

1) Emission rate was estimated based on reference plant information. See criteria pollutant emission calculations. Annual operation includes hours for plant startup.

Nitric Acid Unit

Nitric Acid Unit Operating Hours = 8,052 hr/yr

Compound	CAS #	Hourly (lb/hr)	Annual (lb/yr)
Ammonia (NH3)	8013-59-0	0.51	4,141

Note:

1) Emission rate was estimated based on reference plant information. See criteria pollutant emission calculations. Annual operation includes hours for plant startup.

Data Supplied By Client						
	Onsite Petcoke and Coal Trucks(@ 10 mph)		Product Truck (@ 10 mph)		Miscellaneous Truck (@ 10 mph)	Onsite O&M Trucks (@ 15 mph)
Parameter	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Running Emissions Diesel LHDT2
Distance Traveled (mile)	0.96		2.49		2.20	1.00
Per Truck Idle Time (hour)		0.083		0.083		
No. Volume Sources	34	2	73	7	5	10
Maximum number of trucks or loads						
1-hour	6	6	13	13	5	10
Annual average	15,200	15,200	20,880	20,880	1,818	10000
EMFAC2007 Emission Factors (g/mi/trk or g/idle-hour/trk)						
PM_{10}	0.087	0.114	0.087	0.114	0.087	0.024

EMFAC emissions are for fleet year 2010. PM10 emission factor does not include tire wear or break wear contributions.
Feedstock and Product truck emissions are for HHD diesel trucks. O&M trucks are light heavy-duty 2 trucks.

PM10 Emission Rates

	Onsite Petcoke and Coal Trucks (@ 10 mph)		Product Trucks (@ 10 mph)		Miscellaneous Truck (@ 10 mph)	Onsite O&M Trucks (@ 15 mph)
Emission Rates for HARP	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Running Emissions Diesel LHDT2
1-hr PM_{10} (pounds per hour)	1.0E-03	1.2E-04	6.2E-03	2.7E-04	2.3E-03	5.3E-04
Annual PM_{10} (pounds per year)	2.8E+00	3.2E-01	1.0E+01	4.4E-01	7.7E-01	5.3E-01

HARP Inputs - Annual and Hourly Emission Rates per Volume Source

	Onsite Petcoke and Coal Trucks (@ 10 mph)		Product Trucks (@ 10 mph)		Miscellaneous Truck (@ 10 mph)	Onsite O&M Trucks (@ 15 mph)
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Running Emissions
Max PM_{10} pounds per hour per volume source	3.0E-05	5.8E-05	8.5E-05	3.9E-05	4.6E-04	5.3E-05
PM_{10} pounds per year per volume source	8.2E-02	1.6E-01	1.4E-01	6.2E-02	1.5E-01	5.3E-02

Hydrogen Energy California LLC *4/11/2012*
Hydrogen Energy California (HECA) Project

Maximum Number of Unit Trains	Coal Unit Train (incoming)	Product Unit Train (outgoing)	Maximum Total Trains per period
1-hour	1	1	1
Annual average	109	153	262

	Switching Engine	Line-haul Engine for Coal Train	Line-haul Engine for Product Train
PM10 Emission Factor (g/bhp-hr)	0.10	0.10	0.10
Conversion Factor (bhp-hr/gal)	15.2	20.8	20.8
PM10 Emissions (lbs/hr /engine)	0.057	0.048	0.033
Engine Power Rating (hp)		4400	3000
Notch Operation		1	1
Notch percentage of hp		5.0%	5.0%
Avg Notch horsepower	260	220	150
# of engines per train	1	2	2
hours to unload/load each train		2	1
max operating hours (hrs/year)	1248		
Number of Vome Sources in AERMOD/HARP	104		

Notes:

Switching Engine EPA Tier 3 - 40 CFR Part 1033

The majority of the time the line-haul engine will operate in Notch 1 or idling, therefore emissions were conservatively estimated for Notch 1 horsepower.

Notch percentage presented in PORT OF LONG BEACH AIR EMISSIONS INVENTORY for 2007 (POLB, Jan 2009) derived from EPA data.

New line-haul engines will be AC locomotives such as the GE Evolution Series, that meet Tier 3 emissions

New switching engines will meet Tier 3 emissions, they may be the Titan Trackmobile railcar movers or similar

PM10 Emission Rates

	Switching Engine Emissions	Coal Line-haul Engine Emissions	Product Line-haul Engine Emissions
1-hr PM_{10} (pounds per hour)	0.06	0.10	0.00
Annual PM_{10} (pounds per year)	71.47	21.13	10.11

During a given hour either the line-haul engines for the coal train or product train operate, not both, thus emissions from the larger coal trains are only included in the peak hour emissions.

HARP Inputs - Annual and Hourly Emission Rates per Volume Source

Diesel Particulate Matter	Onsite Train Emissions
Max PM_{10} pounds per hour per volume source	1.5E-03
PM_{10} pounds per year per volume source	9.9E-01

Hydrogen Energy California LLC *4/11/2012*
Hydrogen Energy California (HECA) Project

		Total Uncontrolled Emissions		Total Controlled Emissions	
Compound	**Name**	**Emissions (lb/hr)**	**Emissions (tpy)**	**Emissions (lb/hr)**	**Emissions (tpy)**
CO_2	Carbon dioxide	20.30	88.93	7.37	32.28
CH_4	Methane	0.04	0.19	0.04	0.19
CO	Carbon monoxide	1.07	4.70	1.05	4.62
H_2S	Hydrogen Sulfide	2.10	9.22	0.26	1.14
NH_3	Ammonia	15.12	66.22	1.30	5.70
COS	Carbonyl Sulfide	0.03	0.12	0.01	0.03
CH_3OH	Methanol	17.44	76.39	1.62	7.09
C_3H_6	Proylene	11.44	50.13	1.44	6.33
HCN	Hydrogen Cyanide = Cyanide Compounds	0.002	0.008	0.000	0.001
HNO_3	Nitric acid	2.12	9.29	0.19	0.82
Total VOC	Volatile organic compounds	28.91	126.64	3.07	13.45

Hydrogen Energy California LLC *4/11/2012*
Hydrogen Energy California (HECA) Project

	Total Uncontrolled Emissions		Total Controlled Emissions	
Compound	**Emissions (lb/hr)**	**Emissions (tpy)**	**Emissions (lb/hr)**	**Emissions (tpy)**
CO_2	17.09	74.86	7.12	31.19
CH_4	4.36E-02	1.91E-01	4.31E-02	1.89E-01
CO	1.07	4.70	1.05	4.62
H_2S	2.10	9.22	0.26	1.14
NH_3	0.29	1.26	0.04	0.16
COS	2.76E-02	1.21E-01	6.78E-03	0.03
CH_3OH	17.44	76.39	1.62	7.09
C_3H_6	11.44	50.13	1.44	6.33
HCN	1.73E-03	7.58E-03	1.31E-04	5.73E-04
Total VOC	**28.91**	**126.64**	**3.07**	**13.45**

EPA Table 2-1SOCMI Average Fugitive Emission Factors

Component Type	Service Type	Emission Factor (1) (kg/hr/source)	Control Efficiency (%) (3)
Valves	Gas	5.97E-03	92%
	Light Liquid	4.03E-03	88%
	Heavy Liquid	2.30E-04	
Pump Seals	Light Liquid	1.99E-02	75%
	Heavy Liquid	8.62E-03	
Compressor Seals	Gas	2.28E-01	
Pressure Relief Valves	Gas	1.04E-01	
Connectors	All	1.83E-03	93%
Open-Ended Lines	All	1.70E-03	
Sampling Connections	All	1.50E-02	
Agitator Seals (2)	All	1.99E-02	

Note:
Source: EPA 1995, Protocol for Equipment Leak Emission Estimates
(1) Factors are for total organic compound emission rates. Emission factors assumed to be same for other constituents emitted from the stream.
(2) Factors for light liquid pump seals can be used to estimate the leak rate from agitator seals
(3) Control efficiencies for an LDAR program at a SOCMI process unit using HON reg neg
(control effectiveness attributable to requirements of the hazardous NESHAPS equipment leak regulations)
Emission are conservative since many of these streams are not as volatile as the streams that the SOCMI factors were developed for.

Area #1: Methanol

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	50	8760	0.66	2.88	0.05	0.23
Valves	Light Liquid	416	8760	3.70	16.19	0.44	1.94
Valves	Heavy Liquid	0	8760	-	-	-	-
Pump Seals	Light Liquid	7	8760	0.31	1.35	0.08	0.34
Pump Seals	Heavy Liquid	0	8760	-	-	-	-
Compressor Seals	Gas	0	8760	-	-	-	-
Connectors	All	1225	8760	4.94	21.65	0.35	1.52
			Total	**9.60**	**42.06**	**0.92**	**4.02**
			CH_3OH	9.60	42.06	0.92	4.02

Area #2: Syn Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy
Valves	Gas	108	8760	0.56	2.44
Valves	Light Liquid	0	8760	-	-
Valves	Heavy Liquid	0	8760	-	-
Pump Seals	Light Liquid	0	8760	-	-
Pump Seals	Heavy Liquid	0	8760	-	-
Compressor Seals	Gas	0	8760	-	-
Connectors	All	372	8760	0.59	2.58
			Total	**1.15**	**5.02**
			CO_2	1.69E-01	0.74
			CH_4	1.14E-02	4.99E-02
			CO	0.95	4.16
			H_2S	1.26E-02	5.50E-02
			NH_3	2.92E-05	1.28E-04
			COS	4.38E-03	1.92E-02

Area #4: Shifted Syn Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy
Valves	Gas	198	8760	2.19	9.60
Valves	Light Liquid	0	8760	-	-
Valves	Heavy Liquid	0	8760	-	-
Pump Seals	Light Liquid	0	8760	-	-
Pump Seals	Heavy Liquid	0	8760	-	-
Compressor Seals	Gas	1	8760	0.42	1.85
Connectors	All	632	8760	2.14	9.39
			Total	**4.76**	**20.84**
			CO_2	4.58	20.08
			CH_4	3.17E-02	1.39E-01
			CO	9.68E-02	4.24E-01
			H_2S	4.47E-02	1.96E-01

Area #5: Propylene

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	188	8760	2.47	10.84	0.20	0.87
Valves	Light Liquid	288	8760	2.56	11.21	0.31	1.34
Valves	Heavy Liquid	0	8760	-	-	-	-
Pump Seals	Light Liquid	3	8760	0.13	0.58	0.03	0.14
Pump Seals	Heavy Liquid	0	8760	-	-	-	-
Compressor Seals	Gas	1	8760	0.50	2.20	0.50	2.20
Connectors	All	1432	8760	5.78	25.30	0.40	1.77
			Total	**11.44**	**50.13**	**1.44**	**6.33**
			C_3H_6	11.44	50.13	1.44	6.33

Area #6: Sour Water

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy
Valves	Gas	0	8760	-	-
Valves	Light Liquid	0	8760	-	-
Valves	Heavy Liquid	508	8760	0.01	0.03
Pump Seals	Light Liquid	0	8760	-	-
Pump Seals	Heavy Liquid	17	8760	0.01	0.04
Compressor Seals	Gas	0	8760	-	-
Connectors	All	1410	8760	0.17	0.73
			Total	**0.18**	**0.81**
			CO_2	0.16	0.69
			CO	8.79E-05	3.85E-04
			H_2S	0.01	0.05
			NH_3	0.02	0.07

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Area #7: H_2S Laden Methanol

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	94	8760	1.24	5.42	0.10	0.43
Valves	Light Liquid	358	8760	3.18	13.93	0.38	1.67
Valves	Heavy Liquid	0	8760	-	-	-	-
Pump Seals	Light Liquid	7	8760	0.31	1.34	0.08	0.34
Pump Seals	Heavy Liquid	0	8760	-	-	-	-
Compressor Seals	Gas	0	8760	-	-	-	-
Connectors	All	1323	8760	5.34	23.37	0.37	1.64
			Total	**10.06**	**44.06**	**0.93**	**4.08**
			CO_2	4.50	19.69	0.42	1.82
			CH_4	2.94E-04	1.29E-03	2.72E-05	1.19E-04
			CO	3.47E-03	0.02	3.21E-04	1.41E-03
			H_2S	0.17	0.76	0.02	0.07
			COS	7.50E-04	3.28E-03	6.94E-05	3.04E-04
			CH_3OH	5.38	23.58	0.50	2.18

Area #8: CO_2 Laden Methanol

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	79	8760	1.04	4.55	0.08	0.36
Valves	Light Liquid	79	8760	0.70	3.07	0.08	0.37
Valves	Heavy Liquid	0	8760	-	-	-	-
Pump Seals	Light Liquid	0	8760	-	-	-	-
Pump Seals	Heavy Liquid	0	8760	-	-	-	-
Compressor Seals	Gas	0	8760	-	-	-	-
Connectors	All	516	8760	2.08	9.11	0.15	0.64
			Total	**3.82**	**16.74**	**0.31**	**1.37**
			CO_2	1.37	6.00	0.11	0.49
			CH_4	1.17E-04	5.11E-04	9.55E-06	4.18E-05
			CO	1.37E-03	0.01	1.12E-04	4.90E-04
			H_2S	3.70E-06	1.62E-05	3.03E-07	1.33E-06
			CH_3OH	2.45	10.73	0.20	0.88

Area #9: Acid Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	161	8760	2.12	9.28	0.17	0.74
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Pump Seals	Light Liquid	0	8760	-	-	-	-
Pump Seals	Heavy Liquid	0	8760	-	-	-	-
Compressor Seals	Gas	0	8760	-	-	-	-
Connectors	All	492	8760	1.98	8.69	0.14	0.61
			Total	**4.10**	**17.97**	**0.31**	**1.35**
			CO_2	2.48	10.84	0.19	0.81
			CH_4	7.19E-05	3.15E-04	5.40E-06	2.37E-05
			CO	2.65E-03	0.01	1.99E-04	8.72E-04
			H_2S	1.60	7.02	0.12	0.53
			COS	0.02	0.09	1.57E-03	0.01
			CH_3OH	1.39E-03	0.01	1.04E-04	4.57E-04

Area #10: Ammonia-Laden Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	157	8760	1.70	7.43	0.14	0.59
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Pump Seals	Light Liquid	0	8760	-	-	-	-
Pump Seals	Heavy Liquid	0	8760	-	-	-	-
Compressor Seals	Gas	0	8760	-	-	-	-
Connectors	All	407	8760	1.35	5.90	0.09	0.41
			Total	**3.04**	**13.34**	**0.23**	**1.01**
			CO_2	2.53	11.10	0.19	0.84
			CH_4	7.67E-05	3.36E-04	5.79E-06	2.54E-05
			CO	0.01	0.06	1.02E-03	4.47E-03
			H_2S	0.22	0.97	0.02	0.07
			NH_3	0.27	1.20	0.02	0.09
			COS	8.03E-04	3.52E-03	6.07E-05	2.66E-04
			HCN	1.73E-03	0.01	1.31E-04	5.73E-04

Area #11: Sulfur

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy
Valves	Gas	0	8760	-	-
Valves	Light Liquid	0	8760	-	-
Valves	Heavy Liquid	37	8760	5.56E-06	2.44E-05
Pump Seals	Light Liquid	0	8760	-	-
Pump Seals	Heavy Liquid	2	8760	1.13E-05	4.94E-05
Compressor Seals	Gas	0	8760	-	-
Connectors	All	159	8760	1.90E-04	8.33E-04
			Total	**2.07E-04**	**9.07E-04**
			H_2S	2.07E-04	9.07E-04

Area #12: TGTU Process Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy
Valves	Gas	53	8760	0.47	2.04
Valves	Light Liquid	0	8760	-	-
Valves	Heavy Liquid	0	8760	-	-
Pump Seals	Light Liquid	0	8760	-	-
Pump Seals	Heavy Liquid	0	8760	-	-
Compressor Seals	Gas	1	8760	0.34	1.47
Connectors	All	203	8760	0.55	2.40
			Total	**1.35**	**5.91**
			CO_2	1.31	5.72
			CO	0.01	0.03
			H_2S	0.04	0.16
			COS	6.94E-04	3.04E-03

Note:
Please note that component counts listed in the tables above are only estimates, and do not represent exact component counts

E_{TOC} = $F_A * WF_{TOC} * N$

Where:
F_A = Applicable average emisison factor for equipment type
WF_{TOC} = Average weight fraction of TOC in the stream
N = Number of pieces of equipment of the applicable equipment type

The SOCMI emission factor does not need to be corrected for methane in the stream, because the emission factor is for total organic compounds.

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Area Speciation

Comound	Wt % ($WF_{Constituents}$)										
	Stream 1 Methanol	Stream 2 Syn Gas	Stream 4 Shifted Syn Gas	Stream 5 Propylene	Stream 6 Sour Water	Stream 7 H_2S Laden Methanol	Stream 8 CO_2 Laden Methanol	Stream 9 Acid Gas	Stream 10 Ammonia-Laden Gas	Stream 11 Sulfur	Stream 12 TGTU Process Gas
CO_2	0.0000%	5.7900%	81.0200%	0.0000%	2.5007%	44.6797%	35.8142%	60.3215%	68.3203%	0.0000%	64.6507%
CH_4	0.0000%	0.3900%	0.5600%	0.0000%	0.0000%	0.0029%	0.0030%	0.0018%	0.0021%	0.0000%	0.0000%
CO	0.0000%	32.4900%	1.7100%	0.0000%	0.0014%	0.0345%	0.0358%	0.0645%	0.3642%	0.0000%	0.3054%
H_2S	0.0000%	0.4300%	0.7900%	0.0000%	0.1819%	1.7268%	0.0001%	39.0430%	5.9832%	0.0296%	1.8596%
NH_3	0.0000%	0.0010%	0.0000%	0.0000%	0.2497%	0.0000%	0.0000%	0.0000%	7.3602%	0.0000%	0.0000%
COS	0.0000%	0.1500%	0.0000%	0.0000%	0.0000%	0.0075%	0.0000%	0.5105%	0.0216%	0.0000%	0.0344%
CH_3OH	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	53.5058%	64.1012%	0.0339%	0.0000%	0.0000%	0.0000%
C_3H_6	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
HCN	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0467%	0.0000%	0.0000%
$WF_{Constituents}$ [1]	**100.00%**	**39.25%**	**84.08%**	**100.00%**	**2.93%**	**99.96%**	**99.95%**	**99.98%**	**82.10%**	**0.03%**	**66.85%**

Conversion Note:
1 kg = 2.20 pound

Note:
(1) $WF_{Constituents}$ does not always equal 100% due to the presence of inerts in the area not listed in table above.

Component Count	Process Area										
	1	2	4	5	6	7	8	9	10	11	12
	Methanol	Syn Gas	Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	TGTU Process Gas
Valves - Gas	50	108	198	188	0	94	79	161	157	0	53
Valves - Light Liquid	416	0	0	288	0	358	79	0	0	0	0
Valves - Heavy Liquid	0	0	0	0	508	0	0	0	0	37	0
Pumps - Light Liquid	7	0	0	3	0	7	0	0	0	0	0
Pumps - Heavy Liquid	0	0	0	0	17	0	0	0	0	2	0
Compressors	0	0	1	1	0	0	0	0	0	0	1
Connectors	1225	372	632	1432	1410	1323	516	492	407	159	203
	1698	**480**	**831**	**1912**	**1935**	**1782**	**674**	**653**	**564**	**198**	**257**

	Process Area											
	1	2	4	5	6	7	8	9	10	11	12	
	Methanol	Syn Gas	Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	TGTU Process Gas	Total
Compound	Annual Fugitive Emissions with LDAR Application (ton/yr)											
CO_2		0.74	20.08		0.69	1.82	0.49	0.81	0.84		5.72	31.19
CH_4		0.05	0.14			0.00	0.00	0.00	0.00			0.19
CO		4.16	0.42		0.00	0.00	0.00	0.00	0.00		0.03	4.62
H_2S		0.06	0.20		0.05	0.07	0.00	0.53	0.07	0.00	0.16	1.14
NH_3		0.00			0.07				0.09			0.16
COS		0.02				0.00		0.01	0.00		0.00	0.03
CH_3OH	4.02					2.18	0.88	0.00				7.09
C_3H_6				6.33								6.33
HCN									0.00			0.00
Total VOC	**4.02**	**0.02**	**0.00**	**6.33**	**0.00**	**2.18**	**0.88**	**0.01**	**0.00**	**0.00**	**0.00**	**13.45**
Total percentage of VOC content of gas in each process area	100.00%	0.15%	0.00%	100.00%	0.00%	53.51%	64.10%	0.54%	0.07%	0.00%	0.03%	

Note: The following compounds are included as VOCs, although not all compounds are found in the gas in each process area.
CH_3OH, C_3H_6, COS, and HCN

Summary by Volume Source for Modeling - Emissions are divided by number of Volume Sources

"GASIFICATION" (Area #2)

	lb/hr	lb/yr
CO	0.316	2,772.38
H_2S	4.19E-03	36.69
NH_3	9.74E-06	8.53E-02
CH_3OH		
C_3H_6		
HCN		

3 number of Volume Sources
28 horizontal dimension (m)
46.48 release ht (m)
13.02 horizontal dimension (m)
43.24 vertical dimension (m)
305 vertical dimension used for calcs (ft)

"SHIFT" (Area #4, 6)

	lb/hr	lb/yr
CO	4.84E-02	424.19
H_2S	2.81E-02	245.74
NH_3	7.83E-03	68.56
CH_3OH		
C_3H_6		
HCN		

2 number of Volume Sources
35 horizontal dimension (m)
6.10 release ht (m)
16.28 horizontal dimension (m)
5.67 vertical dimension (m)
40 vertical dimension used for calcs (ft)

"AGR" (Area #1, #5, #7, #8, #9)

	lb/hr	lb/yr
CO	6.32E-04	5.54
H_2S	1.37E-01	1195.86
NH_3		
CH_3OH	1.62E+00	14172.79
C_3H_6	1.44E+00	12657.98
HCN		

1 number of Volume Sources
48 horizontal dimension (m)
6.10 release ht (m)
22.33 horizontal dimension (m)
5.67 vertical dimension (m)
40 vertical dimension used for calcs (ft)

"Sour Water Stripper" (Area #10)

	lb/hr	lb/yr
CO	1.02E-03	8.94
H_2S	1.68E-02	146.89
NH_3	2.06E-02	180.69
CH_3OH		
C_3H_6		
HCN	1.31E-04	1.15

1 number of Volume Sources
16 horizontal dimension (m)
6.10 release ht (m)
7.44 horizontal dimension (m)
5.67 vertical dimension (m)
40 vertical dimension used for calcs (ft)

"SRU" (Area #11, #12)
2 number of Volume Sources

	lb/hr	lb/yr
CO	3.08E-03	27.01
H_2S	1.89E-02	165.37
NH_3		
CH_3OH		
C_3H_6		
HCN		

2 number of Volume Sources
16 horizontal dimension (m)
6.10 release ht (m)
7.44 horizontal dimension (m)
5.67 vertical dimension (m)
40 vertical dimension used for calcs (ft)

Note: Selective LDAR program was applied to Areas # 1#5, #7, #8, #9, #10 due to high uncontrolled emissions for the VOCs (methanol and propylene) and hydrogen sulfide

Fugitive Emissions - UAN Unit

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	Total Uncontrolled Emissions		Total Controlled Emissions	
Compound	**Emissions (lb/hr)**	**Emissions (tpy)**	**Emissions (lb/hr)**	**Emissions (tpy)**
NH_3	2.31	10.14	0.23	0.99
CO_2	0.28	1.23	0.02	0.09
HNO_3	2.12	9.29	0.19	0.82

Summary by Volume Source - Emissions are divided by number of Volume Sources

"Unit 84" Three Volume Sources

	lb/hr	lb/yr
NH_3	0.08	660.02
CO_2	0.01	62.96
HNO_3	0.06	546.25

EPA Table 2-1SOCMI Average Fugitive Emission Factors

Component Type	Service Type	Emission Factor (1) (kg/hr/source)	Control Efficiency (%) (3)
Valves	Gas	5.97E-03	92%
	Light Liquid	4.03E-03	88%
	Heavy Liquid	2.30E-04	
Pump Seals	Light Liquid	1.99E-02	75%
	Heavy Liquid	8.62E-03	
Compressor Seals	Gas	2.28E-01	
Pressure Relief Valves	Gas	1.04E-01	
Connectors	All	1.83E-03	93%
Open-Ended Lines	All	1.70E-03	
Sampling Connections	All	1.50E-02	
Agitator Seals (2)	All	1.99E-02	

Note:
Source: EPA 1995, Protocol for Equipment Leak Emission Estimates
(1) Factors are for total organic compound emission rates. Emission factors assumed to be same for other constituents emitted from the stream.
(2) Factors for light liquid pump seals can be used to estimate the leak rate from agitator seals
(3) Control efficiencies for an LDAR program at a SOCMI process unit using HON reg neg
(control effectiveness attributable to requirements of the hazardous NESHAPS equipment leak regulations)
It was assumed that factors for connectors can be used to estimate the leak rate from flanges.
Emission are conservative since these streams are not as volatile as the streams that the SOCMI factors were developed for.

Unit # 84: 100 wt% Liquid NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	0	8760	-	-	-	-
Valves	Light Liquid	140	8760	1.24	5.45	0.15	0.65
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	All	195	8760	0.79	3.45	0.06	0.24
			Total	**2.03**	**8.89**	**0.20**	**0.89**
			NH_3	2.03	8.89	0.20	0.89

Unit # 84: 62 wt% Vapor NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	17	8760	0.14	0.61	0.01	0.05
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	33	8760	0.08	0.36	0.01	0.03
			Total	**0.22**	**0.97**	**0.02**	**0.07**
			NH_3	0.22	0.97	0.02	0.07

Unit # 84: 6.3 wt% Vapor NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	33	8760	0.03	0.12	2.19E-03	9.59E-03
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	66	8760	0.02	0.07	1.17E-03	5.14E-03
			Total	**0.04**	**0.19**	**3.36E-03**	**1.47E-02**
			NH_3	0.04	0.19	3.36E-03	1.47E-02

Unit # 84: 2.3 wt% Vapor NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	33	8760	0.01	0.04	7.99E-04	3.50E-03
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	66	8760	0.01	0.03	4.29E-04	1.88E-03
			Total	**0.02**	**0.07**	**1.23E-03**	**5.38E-03**
			NH_3	0.02	0.07	1.23E-03	5.38E-03

Unit # 84: 1 wt% Liquid NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	0	8760	-	-	-	-
Valves	Light Liquid	15	8760	1.33E-03	5.84E-03	1.60E-04	7.00E-04
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	27	8760	1.09E-03	4.77E-03	7.63E-05	3.34E-04
			Total	**2.42E-03**	**1.06E-02**	**2.36E-04**	**1.03E-03**
			NH_3	2.42E-03	1.06E-02	2.36E-04	1.03E-03

Unit # 84: 38 wt% Vapor CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	17	8760	0.09	0.37	6.80E-03	0.03
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	33	8760	0.05	0.22	3.54E-03	0.02
			Total	**0.14**	**0.59**	**1.03E-02**	**0.05**
			CO_2	0.14	0.59	1.03E-02	0.05

Fugitive Emissions - UAN Unit

Hydrogen Energy California LLC 4/11/2012
Hydrogen Energy California (HECA) Project

Unit # 84: 6.4 wt% Vapor CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	60	8760	0.05	0.22	4.04E-03	0.02
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	45	8760	0.01	0.05	8.13E-04	0.00
			Total	**0.06**	**0.27**	**4.86E-03**	**0.02**
			CO_2	0.06	0.27	4.86E-03	0.02

Unit # 84: 3.6 wt% Vapor CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	83	8760	0.04	0.17	0.00	0.01
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	156	8760	0.02	0.10	0.00	0.01
			Total	**0.06**	**0.27**	**0.00**	**0.02**
			CO_2	0.06	0.27	0.00	0.02

Unit # 84: 1.8 wt% Vapor CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	69	8760	0.02	0.07	1.31E-03	5.73E-03
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	63	8760	4.58E-03	0.02	3.20E-04	1.40E-03
			Total	**0.02**	**0.09**	**1.63E-03**	**7.13E-03**
			CO_2	0.02	0.09	1.63E-03	7.13E-03

Unit # 84: 60 wt% Liquid HNO_3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	99	8760	0.78	3.42	0.06	0.27
Valves	Light Liquid	96	8760	0.51	2.24	0.06	0.27
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	264	8760	0.64	2.80	0.04	0.20
			Total	**1.93**	**8.46**	**0.17**	**0.74**
			HNO_3	1.93	8.46	0.17	0.74

Unit # 84: 48 wt% Liquid HNO_3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	0	8760	-	-	-	-
Valves	Light Liquid	24	8760	0.10	0.45	0.01	0.05
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	45	8760	0.09	0.38	0.01	0.03
			Total	**0.19**	**0.83**	**0.02**	**0.08**
			HNO_3	0.19	0.83	0.02	0.08

Note:
Please note that component counts listed in the tables above are only estimates, and do not represent exact component counts

E_{TOC} = $F_A * WF_{TOC} * N$

Where:
F_A = Applicable average emisison factor for equipment type
WF_{TOC} = Average weight fraction of TOC in the stream
N = Number of pieces of equipment of the applicable equipment type

The SOCMI emission factor does not need to be corrected for methane in the stream, because the emission factor is for total organic compounds.

Stream Speciation

Comound	Wt % ($WF_{Constituent}$) 100 wt% Liquid NH3	62 wt% Vapor NH3	6.3 wt% Vapor NH3	2.3 wt% Vapor NH3	1 wt% Liquid NH3	38 wt% Vapor CO2	6.4 wt% Vapor CO2	3.6 wt% Vapor CO2	1.8 wt% Vapor CO2	60 wt% Liquid Nitric Acid	48 wt% Liquid Nitric Acid
NH_3	100.0%	62.0%	6.3%	2.3%	1.0%						
CO_2						38.0%	6.4%	3.6%	1.8%		
Nitric Acid (HNO_3)										60.0%	48.0%
$WF_{Constituents}$ [1]	**100.0%**	**62.0%**	**6.3%**	**2.3%**	**1.0%**	**38.0%**	**6.4%**	**3.6%**	**1.8%**	**60.0%**	**48.0%**

Conversion Note:
1 kg = 2.20 pound

Note:
(1) $WF_{Constituent}$ only shows the constituants that are of concern for air quality permitting, such as VOCs, TACs, criteria pollutants and GHGs

	Stream 100 wt% Liquid NH3	62 wt% Vapor NH3	6.3 wt% Vapor NH3	2.3 wt% Vapor NH3	1 wt% Liquid NH3	38 wt% Vapor CO2	6.4 wt% Vapor CO2	3.6 wt% Vapor CO2	1.8 wt% Vapor CO2	60 wt% Liquid Nitric Acid	48 wt% Liquid Nitric Acid
Valves - Gas	0	17	33	33	0	17	60	83	69	99	0
Valves - Light Liquid	140	0	0	0	15	0	0	0	0	96	24
Valves - Heavy Liquid	0	0	0	0	0	0	0	0	0	0	0
Connectors	195	33	66	66	27	33	45	156	63	264	45
	335	**50**	**99**	**99**	**42**	**50**	**105**	**239**	**132**	**459**	**69**

Compound	Stream 100 wt% Liquid NH3	62 wt% Vapor NH3	6.3 wt% Vapor NH3	2.3 wt% Vapor NH3	1 wt% Liquid NH3	38 wt% Vapor CO2	6.4 wt% Vapor CO2	3.6 wt% Vapor CO2	1.8 wt% Vapor CO2	60 wt% Liquid Nitric Acid	48 wt% Liquid Nitric Acid
	Annual Fugitive Emissions with LDAR Application (ton/yr)										
NH_3	0.89	0.07	0.01	0.01	1.03E-03						
CO_2						0.59	0.27	0.27	0.09		
HNO_3										0.74	0.08

Summary by Volume Source for Modeling - Emissions are divided by number of Volume Sources
UAN Unit

	lb/hr	lb/yr
NH_3	0.226	1,980.07
HNO_3	0.187	1,638.74

1 number of Volume Sources
24 horizontal dimension (m)
6.10 release ht (m)
11.16 horizontal dimension (m)
5.67 vertical dimension (m)
40 vertical dimension used for calcs (ft)

Hydrogen Energy California LLC
Hydrogen Energy California (HECA) Project

4/11/2012

	Total Uncontrolled Emissions		Total Controlled Emissions	
Compound	**Emissions (lb/hr)**	**Emissions (tpy)**	**Emissions (lb/hr)**	**Emissions (tpy)**
NH_3	4.19	18.34	0.40	1.76
CO_2	2.93	12.84	0.23	0.99

Summary by Volume Source - Emissions are divided by number of Volume Sources

"Unit 82" Three Volume Sources

	lb/hr	lb/yr
NH_3	0.13	1,171.95
CO_2	0.08	660.60

EPA Table 2-1SOCMI Average Fugitive Emission Factors

Component Type	Service Type	Emission Factor[1] (kg/hr/source)	Control Efficiency (%) [3]
Valves	Gas	5.97E-03	92%
	Light Liquid	4.03E-03	88%
	Heavy Liquid	2.30E-04	
Pump Seals	Light Liquid	1.99E-02	75%
	Heavy Liquid	8.62E-03	
Compressor Seals	Gas	2.28E-01	
Pressure Relief Valves	Gas	1.04E-01	
Connectors	All	1.83E-03	93%
Open-Ended Lines	All	1.70E-03	
Sampling Connections	All	1.50E-02	
Agitator Seals [2]	All	1.99E-02	

Note:
Source: EPA 1995, Protocol for Equipment Leak Emission Estimates
(1) Factors are for total organic compound emission rates. Emission factors assumed to be same for other constituents emitted from the stream.
(2) Factors for light liquid pump seals can be used to estimate the leak rate from agitator seals
(3) Control efficiencies for an LDAR program at a SOCMI process unit using HON reg neg
(control effectiveness attributable to requirements of the hazardous NESHAPS equipment leak regulations)
It was assumed that factors for connectors can be used to estimate the leak rate from flanges.
Emission are conservative since these streams are not as volatile as the streams that the SOCMI factors were developed for.

Unit # 82: 100 wt% Liquid NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	0	8760	-	-	-	-
Valves	Light Liquid	77	8760	0.68	3.00	0.08	0.36
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	All	141	8760	0.57	2.49	0.04	0.17
			Total	**1.25**	**5.49**	**0.12**	**0.53**
			NH_3	1.25	5.49	0.12	0.53

Unit # 82: 50-70 wt% Liquid NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	0	8760	-	-	-	-
Valves	Light Liquid	47	8760	0.29	1.28	0.04	0.15
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	63	8760	0.18	0.78	0.01	0.05
			Total	**0.47**	**2.06**	**0.05**	**0.21**
			NH_3	0.47	2.06	0.05	0.21

Unit # 82: 25-40 wt% Liquid NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	0	8760	-	-	0.00E+00	0.00E+00
Valves	Light Liquid	117	8760	0.42	1.82	0.05	0.22
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	225	8760	0.36	1.59	2.54E-02	1.11E-01
			Total	**0.78**	**3.41**	**7.53E-02**	**3.30E-01**
			NH_3	0.78	3.41	7.53E-02	3.30E-01

Unit # 82: 0.5-25 wt% Liquid NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	0	8760	-	-	0.00E+00	0.00E+00
Valves	Light Liquid	254	8760	0.56	2.47	0.07	0.30
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	456	8760	0.46	2.01	3.22E-02	1.41E-01
			Total	**1.02**	**4.49**	**9.99E-02**	**4.38E-01**
			NH_3	1.02	4.49	9.99E-02	4.38E-01

Unit # 82: 3-30 wt% Vapor NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	60	8760	0.24	1.04	0.02	0.08
Valves	Light Liquid	60	8760	1.60E-01	7.00E-01	1.92E-02	8.41E-02
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	219	8760	2.65E-01	1.16E+00	1.86E-02	8.13E-02
			Total	**6.62E-01**	**2.90E+00**	**5.67E-02**	**2.48E-01**
			NH_3	6.62E-01	2.90E+00	5.67E-02	2.48E-01

Unit # 82: 30-60 wt% Vapor NH3

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	23	8760	0.18	0.80	1.45E-02	0.06
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	45	8760	0.11	0.48	7.63E-03	0.03
			Total	**0.29**	**1.27**	**2.22E-02**	**0.10**
			NH_3	0.29	1.27	0.02	0.10

Unit # 82: 100 wt% Vapor CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	60	8760	0.79	3.46	6.32E-02	0.28
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	45	8760	0.18	0.80	1.27E-02	0.06
			Total	**0.97**	**4.25**	**7.59E-02**	**0.33**
			CO_2	0.97	4.25	7.59E-02	0.33

Unit # 82: 50-70 wt% Liquid CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	83	8760	0.76	3.35	0.06	0.27
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	156	8760	0.44	1.93	0.03	0.14
			Total	**1.21**	**5.28**	**0.09**	**0.40**
			CO_2	1.21	5.28	0.09	0.40

Fugitive Emissions - Urea Unit

Hydrogen Energy California LLC 4/11/2012
Hydrogen Energy California (HECA) Project

Unit # 82: 25-40 wt% Liquid CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	69	8760	0.36	1.59	2.91E-02	1.27E-01
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	63	8760	1.02E-01	0.45	7.12E-03	3.12E-02
			Total	**0.46**	**2.04**	**3.62E-02**	**1.58E-01**
			CO_2	0.46	2.04	3.62E-02	1.58E-01

Unit # 82: 0.5-25 wt% Liquid CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	26	8760	0.09	0.37	6.84E-03	0.03
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	51	8760	0.05	0.23	3.60E-03	0.02
			Total	**0.14**	**0.60**	**1.04E-02**	**0.05**
			CO_2	0.14	0.60	0.01	0.05

Unit # 82: 2-30 wt% Vapor CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	26	8760	0.10	0.45	8.21E-03	0.04
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	51	8760	0.06	0.27	4.32E-03	0.02
			Total	**0.16**	**0.72**	**1.25E-02**	**0.05**
			CO_2	0.16	0.72	0.01	0.05

Unit # 82: 20-65 wt% Vapor CO_2

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	57	8760	0.49	2.14	3.90E-02	0.17
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	81	8760	0.21	0.93	1.49E-02	0.07
			Total	**0.70**	**3.07**	**5.39E-02**	**0.24**
			CO_2	0.70	3.07	0.05	0.24

Note:
Please note that component counts listed in the tables above are only estimates, and do not represent exact component counts

E_{TOC} = $F_A * WF_{TOC} * N$

Where:
F_A = Applicable average emisison factor for equipment type
WF_{TOC} = Average weight fraction of TOC in the stream
N = Number of pieces of equipment of the applicable equipment type

The SOCMI emission factor does not need to be corrected for methane in the stream, because the emission factor is for total organic compounds.

Stream Speciation

Comound	Wt % ($WF_{Constituent}$) 100 wt% Liquid NH3	50-70 wt% Liquid NH3	25-40 wt% Liquid NH3	0.5-25 wt% Liquid NH3	3-30 wt% Vapor NH3	30-60 wt% Vapor NH3	100 wt% Vapor CO2	50-70 wt% Liquid CO2	25-40 wt% Liquid CO2	0.5-25 wt% Liquid CO2	2-30 wt% Vapor CO2	30-65 wt% Vapor CO2
NH_3	100.0%	70.0%	40.0%	25.0%	30.0%	60.0%						
CO_2							100.0%	70.0%	40.0%	25.0%	30.0%	65.0%
$WF_{Constituents}$ [1]	**100.0%**	**70.0%**	**40.0%**	**25.0%**	**30.0%**	**60.0%**	**100.0%**	**70.0%**	**40.0%**	**25.0%**	**30.0%**	**65.0%**

Conversion Note:
1 kg = 2.20 pound

Note:
(1) $WF_{Constituent}$ only shows the constituants that are of concern for air quality permitting, such as VOCs, TACs, criteria pollutants and GHGs

	Stream 100 wt% Liquid NH3	50-70 wt% Liquid NH3	25-40 wt% Liquid NH3	0.5-25 wt% Liquid NH3	3-30 wt% Vapor NH3	30-60 wt% Vapor NH3	100 wt% Vapor CO2	50-70 wt% Liquid CO2	25-40 wt% Liquid CO2	0.5-25 wt% Liquid CO2	2-30 wt% Vapor CO2	30-65 wt% Vapor CO2
Valves - Gas	0	0	0	0	60	23	60	83	69	26	26	57
Valves - Light Liquid	77	47	117	254	60	0	0	0	0	0	0	0
Valves - Heavy Liquid	0	0	0	0	0	0	0	0	0	0	0	0
Connectors	141	63	225	456	219	45	45	156	63	51	51	81
	218	**110**	**342**	**710**	**339**	**68**	**105**	**239**	**132**	**77**	**77**	**138**

	Stream 100 wt% Liquid NH3	50-70 wt% Liquid NH3	25-40 wt% Liquid NH3	0.5-25 wt% Liquid NH3	3-30 wt% Vapor NH3	30-60 wt% Vapor NH3	100 wt% Vapor CO2	50-70 wt% Liquid CO2	25-40 wt% Liquid CO2	0.5-25 wt% Liquid CO2	2-30 wt% Vapor CO2	30-65 wt% Vapor CO2
Compound	**Annual Fugitive Emissions with LDAR Application (ton/yr)**											
NH_3	0.53	0.21	0.33	0.44	2.48E-01	0.10						
CO_2							0.33	0.40	1.58E-01	0.05	0.05	0.24

Summary by Volume Source for Modeling - Emissions are divided by number of Volume Sources
Urea Unit

	lb/hr	lb/yr
NH_3	0.201	1,758

2 number of Volume Sources
12 horizontal dimension (m)
6.10 release ht (m)
5.58 horizontal dimension (m)
5.67 vertical dimension (m)
40 vertical dimension used for calcs (ft)

Fugitive Emissions - Ammonia Unit

Hydrogen Energy California LLC
Hydrogen Energy California (HECA) Project

4/11/2012

	Total Uncontrolled Emissions		Total Controlled Emissions	
Compound	**Emissions (lb/hr)**	**Emissions (tpy)**	**Emissions (lb/hr)**	**Emissions (tpy)**
NH_3	8.33	36.48	0.64	2.79

Summary by Volume Source - Emissions are divided by number of Volume Sources

"Unit 81" Three Volume Sources

	lb/hr	lb/yr
NH_3	0.21	1,861.32

EPA Table 2-1SOCMI Average Fugitive Emission Factors

Component Type	Service Type	Emission Factor (1) (kg/hr/source)	Control Efficiency (%) (3)
Valves	Gas	5.97E-03	92%
	Light Liquid	4.03E-03	88%
	Heavy Liquid	2.30E-04	
Pump Seals	Light Liquid	1.99E-02	75%
	Heavy Liquid	8.62E-03	
Compressor Seals	Gas	2.28E-01	
Pressure Relief Valves	Gas	1.04E-01	
Connectors	All	1.83E-03	93%
Open-Ended Lines	All	1.70E-03	
Sampling Connections	All	1.50E-02	
Agitator Seals (2)	All	1.99E-02	

Note:
Source: EPA 1995, Protocol for Equipment Leak Emission Estimates
(1) Factors are for total organic compound emission rates. Emission factors assumed to be same for other constituents emitted from the stream.
(2) Factors for light liquid pump seals can be used to estimate the leak rate from agitator seals
(3) Control efficiencies for an LDAR program at a SOCMI process unit using HON reg neg
(control effectiveness attributable to requirements of the hazardous NESHAPS equipment leak regulations)
It was assumed that factors for connectors can be used to estimate the leak rate from flanges.
Emission are conservative since these streams are not as volatile as the streams that the SOCMI factors were developed for.

Unit # 81: 0.14 wt% (or 0.07 mol %) NH3 in Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	177	8760	2.33	10.20	0.19	0.82
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	All	327	8760	1.32	5.78	0.09	0.40
			Total	**3.65**	**15.98**	**0.28**	**1.22**
			NH_3	3.65	15.98	0.28	1.22

Unit # 81: 5.8 wt % (or 3.1 mol %) NH3 in Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	227	8760	2.09	9.16	0.17	0.73
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	378	8760	1.07	4.68	0.07	0.33
			Total	**3.16**	**13.84**	**0.24**	**1.06**
			NH_3	3.16	13.84	0.24	1.06

Unit # 81: 7.8 wt % (or 4.3 mol %) NH3 in Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	84	8760	0.44	1.94	3.54E-02	1.55E-01
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	93	8760	0.15	0.66	1.05E-02	4.60E-02
			Total	**0.59**	**2.59**	**4.59E-02**	**2.01E-01**
			NH_3	0.59	2.59	4.59E-02	2.01E-01

Unit # 81: 32.9 wt % (or 20.7 mol %) NH3 in Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	131	8760	0.43	1.89	3.45E-02	1.51E-01
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	258	8760	0.26	1.14	1.82E-02	7.98E-02
			Total	**0.69**	**3.03**	**5.27E-02**	**2.31E-01**
			NH_3	0.69	3.03	5.27E-02	2.31E-01

Unit # 81: 35.7 wt % (or 31.6 mol %) NH3 in Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	38	8760	0.15	0.66	0.01	0.05
Valves	Light Liquid	0	8760	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	72	8760	8.71E-02	3.82E-01	6.10E-03	2.67E-02
			Total	**2.37E-01**	**1.04E+00**	**1.81E-02**	**7.93E-02**
			NH_3	2.37E-01	1.04E+00	1.81E-02	7.93E-02

Unit # 81: 99.99 wt % (or 99.9 mol %) NH3 in Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy	Controlled Emissions (E_{TOC}) lb/hr	Controlled Emissions (E_{TOC}) tpy
Valves	Gas	414	8760	3.27	14.32	2.62E-01	1.15
Valves	Light Liquid	0	8760	-	-	-	-
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	438	8760	1.06	4.64	7.42E-02	0.33
			Total	**4.33**	**18.96**	**3.36E-01**	**1.47**
			NH_3	4.33	18.96	0.34	1.47

Fugitive Emissions - Ammonia Unit

Hydrogen Energy California LLC 4/11/2012
Hydrogen Energy California (HECA) Project

Unit # 81: 099.99 wt % (or 99.9 mol %) NH3 in Liquid

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC})		Controlled Emissions (E_{TOC})	
				lb/hr	tpy	lb/hr	tpy
Valves	Gas	0	8760	-	-	0.00E+00	-
Valves	Light Liquid	575	8760	5.11	22.38	0.61	2.69
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	732	8760	2.95	12.94	2.07E-01	0.91
			Total	**8.06**	**35.31**	**8.20E-01**	**3.59**
			NH_3	8.06	35.31	8.20E-01	3.59

Unit # 81: 5.61 wt % NH_3 in liquid water

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC})		Controlled Emissions (E_{TOC})	
				lb/hr	tpy	lb/hr	tpy
Valves	Gas	0	8760	-	-	-	-
Valves	Light Liquid	101	8760	0.90	3.93	0.11	0.47
Valves	Heavy Liquid	0	8760	-	-	-	-
Flanges	Light Liquid	186	8760	0.53	2.30	0.04	0.16
			Total	**1.42**	**6.23**	**0.14**	**0.63**
			NH_3	1.42	6.23	0.14	0.63

Note:
Please note that component counts listed in the tables above are only estimates, and do not represent exact component counts

E_{TOC} = $F_A * WF_{TOC} * N$

Where:
F_A = Applicable average emisison factor for equipment type
WF_{TOC} = Average weight fraction of TOC in the stream
N = Number of pieces of equipment of the applicable equipment type

The SOCMI emission factor does not need to be corrected for methane in the stream, because the emission factor is for total organic compounds.

Stream Speciation

Comound	Wt % ($WF_{Constituent}$)							
	0.14 wt % (or 0. 07 mol %) NH3 in gas	5.8 wt % (or 3.1 mol %) NH3 in gas	7.8 wt % (or 4.3 mol %) NH3 in gas	32.9 wt % (or 20.7 mol %) NH3 in gas	35.7 wt % (or 31.6 mol %) NH3 in gas	99.99 wt % (or 99.9 mol %) NH3 in gas	99.99 wt % (or 99.9 mol %) NH3 in liq	5.61 wt % NH3 in liq water
NH_3	100.0%	70.0%	40.0%	25.0%	30.0%	60.0%	100.0%	70.0%
$WF_{Constituents}$ [1]	**100.0%**	**70.0%**	**40.0%**	**25.0%**	**30.0%**	**60.0%**	**100.0%**	**70.0%**

Conversion Note:
1 kg = 2.20 pound

Note:
(1) $WF_{Constituent}$ only shows the constituants that are of concern for air quality permitting, such as VOCs, TACs, criteria pollutants and GHGs

	Stream							
	0.14 wt % (or 0. 07 mol %) NH3 in gas	5.8 wt % (or 3.1 mol %) NH3 in gas	7.8 wt % (or 4.3 mol %) NH3 in gas	32.9 wt % (or 20.7 mol %) NH3 in gas	35.7 wt % (or 31.6 mol %) NH3 in gas	99.99 wt % (or 99.9 mol %) NH3 in gas	99.99 wt % (or 99.9 mol %) NH3 in liq	5.61 wt % NH3 in liq water
Valves - Gas	177	227	84	131	38	414	0	0
Valves - Light Liquid	0	0	0	0	0	0	575	101
Valves - Heavy Liquid	0	0	0	0	0	0	0	0
Connectors	327	378	93	258	72	438	732	186
	504	**605**	**177**	**389**	**110**	**852**	**1307**	**287**

	Stream							
	0.14 wt % (or 0. 07 mol %) NH3 in gas	5.8 wt % (or 3.1 mol %) NH3 in gas	7.8 wt % (or 4.3 mol %) NH3 in gas	32.9 wt % (or 20.7 mol %) NH3 in gas	35.7 wt % (or 31.6 mol %) NH3 in gas	99.99 wt % (or 99.9 mol %) NH3 in gas	99.99 wt % (or 99.9 mol %) NH3 in liq	5.61 wt % NH3 in liq water
Compound	**Annual Fugitive Emissions with LDAR Application (ton/yr)**							
NH_3	1.22	1.06	0.20	0.23	7.93E-02	1.47	3.59	0.63

Summary by Volume Source for Modeling - Emissions are divided by number of Volume Sources
Ammonia Unit

	lb/hr	lb/yr
NH_3	0.319	2,792

2 number of Volume Sources
24 horizontal dimension (m)
6.10 release ht (m)
11.16 horizontal dimension (m)
5.67 vertical dimension (m)
40 vertical dimension used for calcs (ft)

Total Reduced Sulfur

Pollutant	Annual Rate (tons per year)	TRS as H2S (tons/yr)	Molecular Wt	Source of emissions		
Hydrogen Sulfide	2.64	2.64	34	CO_2 vent and fugitives		
Carbonyl Sulfide	2.69	1.53	60	CO_2 vent and fugitives	**Significance Threshold (tons/yr)**	**Significant?**
	Total	**4.17**			10.00	no

TRS definition: the total reduced sulfur contained in hydrogen sulfide, mercaptans, dimethyl sulfide, dimethyl disulfide or other organic sulfide compounds, all expressed as hydrogen sulfide. Sulfur dioxide, sulfur trioxide, or sulfuric acid are not to be included in the determination of TRS.

Reduced Sulfur Compounds

Pollutant	Annual Rate (tons per year)	RSC as H2S (tons/yr)	Molecular Wt	Source of emissions		
Hydrogen Sulfide	2.64	2.64	34	CO_2 vent and fugitives		
Carbon Disulfide	0.55	0.25	76	CTG/HRSG and coal dryer		
Carbonyl Sulfide	2.69	1.53	60	CO_2 vent and fugitives	**Significance Threshold (tons/yr)**	**Significant?**
	Total	**4.42**			10.00	no

Reduced sulfur compounds means H2S, carbonyl sulfide (COS), and carbon disulfide (CS2).

Sulfuric Acid Mist

Pollutant	Annual Rate (tons per year)	Significance Threshold (tons/yr)	Significant ?	Source of emissions
Sulfuric Acid Mist	1.14	7.00	no	CTG/HRSG and coal dryer

Hydrogen Sulfide

Pollutant	Annual Rate (tons per year)	Significance Threshold (tons/yr)	Significant ?	Source of emissions
Hydrogen Sulfide	2.64	10.00	no	CO_2 vent and fugitives

Fluorides

Pollutant	Annual Rate (tons per year)	Significance Threshold (tons/yr)	Significant ?	Source of emissions
Fluoride	0.001	3.00	no	Cooling towers

Lead

Pollutant	Annual Rate (tons per year)	Significance Threshold (tons/yr)	Significant ?	Source of emissions
Lead	0.007	0.60	no	CTG/HRSG and coal dryer

Pollutants listed above are in 40 CFR 52.21 (as of Apr 6, 2012)

Appendix G

Operational Greenhouse Gas Emissions

Hydrogen Energy California LLC *5/21/2012*
HECA Project

HECA Maximum Annual CO2e Emissions

Source	Permitted CO2e Emissions (tonne/year)
CTG/HRSG Hydrogen-Rich Fuel and PSA Off-gas	269,153
CTG/HRSG Natural Gas	44,772
CO_2 Vent	174,113
SF_6 Circuit breakers	86
Flares	8,257
Thermal Oxidizer	5,946
Emergency generators and fire pump	181
Auxiliary boiler	24,782
Ammonia Synthesis Plant Startup Heater	409
Urea Absorber Vents	116
Nitric Acid Unit	7,426
Fugitives	35
Total CO2e Annual Emissions	**535,278**

Notes:
Maximum permitted emissions include periods of startup and shutdown.

Hydrogen Energy California LLC *5/21/2012*
HECA Project

HECA Annual CO2 Emissions for SB1368 Emission Performance Standard

Operating Parameters	Early Operations (Maximum Permitted)	Mature Operations	Expected Mature Syngas Operations
Natural Gas Operation, hours per year	351	351	15
Hydrogen-rich Fuel Operation, hours per year	8,108	8,108	8,108
Intermittent CO_2 Venting, hours per year	504	120	0
Electricity Generated, MWh	2,699,860	2,699,860	2,599,060
Source	**CO2 Emissions (Metric Ton/year)**		
CTG/HRSG Hydrogen-Rich Fuel and PSA Off-gas	258,856	258,856	258,856
CTG/HRSG Natural Gas	44,729	44,729	1,911
CO_2 Vent	174,113	41,456	0
Fugitives	31	31	31
Total CO2 Annual Emissions	**477,729**	**345,071**	**260,799**
CO2 lb/MWh	390.0	281.7	221.2

Notes:

Early operations Maximum permitted emissions include 2 periods of start-up and shut-down, natural gas use in the CTG and 504 hours of CO2 venting.

Mature operations emissions include 2 periods of start-up and shut-down, natural gas use in the CTG and 120 hours of CO2 venting.

During expected mature operation, the CTG and duct burners will fire only hydrogen-rich fuel and PSA off-gas, it includes 2 startups and shutdown (which includes natural gas), but no natural gas backup use and no CO2 venting.

The fugitive CO_2 emissions are from all process areas, therefore overestimate the emissions from the sequestration process.

Power Production

Hydrogen-rich Fuel Operation		
Net Power Exported	267	MW
Fertilizer Production Power	58	MW
Steam Produced by Fertilizer Production	-5	MW
Net Power	**320**	MW
Natural Gas Operation		
Net Power Exported	**300**	MW

SB1368

Emission caclulation

Emissions include annual carbon dioxide emissions from each fuel used in any component directly involved in electricity production associated with the sequestration of the CO2.

Emissions from electricity production come from the CTG/HRSG and coal dryer when burning syngas, PSA off-gas and natural gas

Emissions associated with the CO2 sequestration include CO2 vent and fugitives from CO2 preparation for sequestration.

Circuit breakers are not included in this inventory as these do not emit CO2.

The SB1368 emission calculations do not include emissions associated with the gasification block (flares, thermal oxidizer), fertilizer complex (Ammonia Synthesis Plant Startup Heater, Urea Absorbers, nitric acid unit), auxiliary boiler, emergency generators, fire pump, and vehicles.

MW caclulation

The net electricity production includes the net power exported plus the power used onsite in the Manufacturing Complex minus the steam generated from the Manufacturing Complex.

The net power exported justification is provided in Section 2, Project Description.

GHG Emissions from Stationary Sources

Hydrogen Energy California LLC *5/21/2012*
HECA Project

GHG emissions are numerically depicted as metric tons (tonne) of carbon dioxide equivalents (CO_2e). CO_2e represents CO_2 plus the additional warming potential from CH_4 and N_2O. CH_4 and N_2O have 21 and 310 times the warming potential of CO_2, respectively.

Natural Gas GHG Emission Factors						Diesel GHG Emission Factors				
CO_2 =	53.06	kg/MMBtu =	116.98	lb/MMBtu		CO_2 =	10.15	kg/gal =	22.38	lb/gal
CH_4 =	0.001	kg/MMBtu =	0.002	lb/MMBtu		CH_4 =	0.0004	kg/gal =	0.001	lb/gal
N_2O =	0.0001	kg/MMBtu =	0.00022	lb/MMBtu		N_2O =	0.0001	kg/gal =	0.0002	lb/gal

CO_2, CH_4, and N_2O emission factors are taken from Appendix C of the California Climate Action Registry (CCAR) General Reporting Protocol Version 3.1 (Jan 2009)

Turbine - Burning Hydrogen-Rich Fuel - released to HRSG and Coal Dryer Stacks

Operating Hours		8108	hr/yr		**Syngas GHG Emission Factors**		
Heat Input (HHV)		2,537	MMBtu/hr		CO_2 =	17.7	lb/MMBtu
					CH_4 =	0.03	lb/MMBtu
CO_2 =	165,200	tonne/yr					
CH_4 =	291	tonne/yr =	6,116	tonne CO_2e/yr			
N_2O =	2.06	tonne/yr =	638	tonne CO_2e/yr	Total tonne CO_2e/yr =		171,953

HRSG heat input rate is based Case 5, average ambient temperature and peak load.

Operating hours include startup and shutdown operations

Although N2O emissions are expected to be lower than from the combustion of natural gas, N2O emissions were conservatively estimated using the natural gas emission factor.

Duct burner - Burning Hydrogen-Rich Fuel - released to HRSG and Coal Dryer Stacks

Operating Hours		8000	hr/yr		**Syngas GHG Emission Factors**		
Heat Input (HHV)		165	MMBtu/hr		CO_2 =	17.7	lb/MMBtu
					CH_4 =	0.03	lb/MMBtu
CO_2 =	10,603	tonne/yr					
CH_4 =	19	tonne/yr =	393	tonne CO_2e/yr			
N_2O =	0.13	tonne/yr =	41	tonne CO_2e/yr	Total tonne CO_2e/yr =		11,036

Duct burner heat input rate is based Case 5, average ambient temperature and peak load.

Duct burner not operated during turbine startup and shutdown

Although N2O emissions are expected to be lower than from the combustion of natural gas, N2O emissions were conservatively estimated using the natural gas emission factor.

Duct burner - Burning PSA Offgas - released to HRSG and Coal Dryer Stacks

Operating Hours		8,000	hr/yr		**Syngas GHG Emission Factors**		
Heat Input (HHV)		149	MMBtu/hr		CO_2 =	153.6	lb/MMBtu
					CH_4 =	0.3	lb/MMBtu
CO_2 =	83,053	tonne/yr					
CH_4 =	146	tonne/yr =	3,073	tonne CO_2e/yr			
N_2O =	0.12	tonne/yr =	37	tonne CO_2e/yr	Total tonne CO_2e/yr =		86,163

Duct burner heat input rate is based Case 5, average ambient temperature and peak load.

Duct burner not operated during turbine startup and shutdown

Although N2O emissions are expected to be lower than from the combustion of natural gas, N2O emissions were conservatively estimated using the natural gas emission factor.

Turbine - Burning Natural Gas - released to HRSG Stack

Operating Hours		351	hr/yr			
Heat Input (HHV)		2,401	MMBtu/hr			
CO_2 =	44,729	tonne/yr				
CH_4 =	0.84	tonne/yr =	18	tonne CO_2e/yr		
N_2O =	0.08	tonne/yr =	26	tonne CO_2e/yr	Total tonne CO_2e/yr =	44,772

HRSG heat input rate is assumed to be the maximum heat input rate firing natural gas. Hours of operation include startup and shutdown.

Auxiliary Boiler

Operating Hours		2,190	hr/yr			
Heat Input		213	MMBtu/hr			
CO_2 =	24,758	tonne/yr				
CH_4 =	0	tonne/yr =	10	tonne CO_2e/yr		
N_2O =	0.05	tonne/yr =	14	tonne CO_2e/yr	Total tonne CO_2e/yr =	24,782

GHG Emissions from Stationary Sources

Hydrogen Energy California LLC *5/21/2012*
HECA Project

Emergency Generators (2)

Operating Hours		50	hr/yr			
Heat Input		2,922	Bhp			
CO_2 =	3,341	lb/hr =	76	tonne CO_2/yr		
CH_4 =	0.13	lb/hr =	0.063	tonne CO_2e/yr		
N_2O =	0.03	lb/hr =	0.2315	tonne CO_2e/yr	Total tonne CO_2e/yr* =	152

The following conversions were used to convert from lb/gallon to lb/hp-hour; and then multiplying by the rated horsepower rating: 1 gallon/137,000 Btu; and 7,000 Btu/hp-hour.

* Total tonnes CO_2e per year represent the contributions from both generators.

Fire Water Pump

Operating Hours		100	hr/yr			
Heat Input		556	Bhp			
CO_2 =	636	lb/hr =	29	tonne CO_2/yr		
CH_4 =	0.03	lb/hr =	0.024	tonne CO_2e/yr		
N_2O =	0.01	lb/hr =	0.0881	tonne CO_2e/yr	Total tonne CO_2e/yr =	29

The following conversions were used to convert from lb/gallon to lb/hp-hour; and then multiplying by the rated horsepower rating: 1 gallon/137,000 Btu; and 7,000 Btu/hp-hour.

Gasification Flare

Pilot Operation						
Operating Hours		8,760	hr/yr			
Heat Input		0.5	MMBtu/hr			
CO_2 =	232	tonne/yr				
CH_4 =	0.00	tonne/yr =	0.1	tonne CO_2e/yr		
N_2O =	0.0004	tonne/yr =	0.1	tonne CO_2e/yr	Total tonne CO_2e/yr =	233
Flaring Events						
Total Operation		70,536	MMBtu/yr			
CO_2 =	3,744	tonne/yr				
CH_4 =	0.1	tonne/yr =	1	tonne CO_2e/yr		
N_2O =	0.01	tonne/yr =	2	tonne CO_2e/yr	Total tonne CO_2e/yr =	3,747

GHG emissions from flaring events are conservatively estimated using GHG emission factors for natural gas combustion.

Rectisol Flare

Pilot Operation						
Operating Hours		8,760	hr/yr			
Heat Input		0.3	MMBtu/hr			
CO_2 =	139	tonne/yr				
CH_4 =	0.00	tonne/yr =	0.1	tonne CO_2e/yr		
N_2O =	0.0003	tonne/yr =	0.08	tonne CO_2e/yr	Total tonne CO_2e/yr =	140
Flaring Events						
Operating Hours		40	hr/yr			
Vent gas flow		4542	lb-mole/hr			
CO_2 =	3,627	tonne/yr				
CH_4 =		tonne/yr =		tonne CO_2e/yr		
N_2O =		tonne/yr =		tonne CO_2e/yr	Total tonne CO_2e/yr =	3,627

GHG emissions from flaring event based on 100% carbon content of the gas during startup.

SRU Flare

Pilot Operation						
Operating Hours		8,760	hr/yr			
Heat Input		0.3	MMBtu/hr			
CO_2 =	139	tonne/yr				
CH_4 =	0.00	tonne/yr =	0.1	tonne CO_2e/yr		
N_2O =	0.0003	tonne/yr =	0.08	tonne CO_2e/yr	Total tonne CO_2e/yr =	140
Flaring Events - natural gas assist for acid gas venting during startup						
Operating Hours		40	hr/yr			
Heat Input		36	MMBtu/hr			
Throughput (inerts) - acid gas venting during startup						
CO_2 =		140000	scf/hr			
CO_2 =		16,240	lb/hr			
CO_2 =	371	tonne/yr				
CH_4 =	0.001	tonne/yr =	0.03	tonne CO_2e/yr		
N_2O =	0.00014	tonne/yr =	0.045	tonne CO_2e/yr	Total tonne CO_2e/yr =	371

Throughtput (inerts) provided from design engineers.

Tail Gas Thermal Oxidizer

Process Vent Disposal Emissions						
Operating Hours		8,314	hr/yr			
Heat Input		13	MMBtu/hr			
CO_2 =	5,736	tonne/yr				
CH_4 =	0.11	tonne/yr =	2.3	tonne CO_2e/yr		
N_2O =	0.0108	tonne/yr =	3.4	tonne CO_2e/yr	Total tonne CO_2e/yr =	5,742
SRU Startup Waste Gas Disposal						
Operating Hours		48	hr/yr			
Heat Input		80	MMBtu/hr			
CO_2 =	204	tonne/yr				
CH_4 =	0.004	tonne/yr =	0.08	tonne CO_2e/yr		
N_2O =	0.00038	tonne/yr =	0.119	tonne CO_2e/yr	Total tonne CO_2e/yr =	204

GHG emissions from thermal oxidizer are estimated using GHG emission factors for natural gas combustion for the assist gas.

Intermittent CO_2 Vent

Operating Hours		504	hr/yr		
CO_2 Emission Rate		761,400	lb/hr		
				Total tonne CO_2e/yr =	174,113

Assumes 504 hours per year venting at full rate.

Fugitives

Operating Hours		8,760	hr/yr			
CO_2 =	32.3	tpy	31.37	tonne CO_2e/yr		
CH_4 =	0.19	tpy	3.86	tonne CO_2e/yr		
					Total tonne CO_2e/yr =	35

Detailed emission calculations are provided in Appendix M, Public Health.

Ammonia Synthesis Plant Startup Heater

Operating Hours		140	hr/yr			
Heat Input		55	MMBtu/hr			
CO_2 =	409	tonne/yr				
CH_4 =	0	tonne/yr =	0	tonne CO_2e/yr		
N_2O =	0.00	tonne/yr =	0	tonne CO_2e/yr	Total tonne CO_2e/yr =	409

GHG Emissions from Stationary Sources

Hydrogen Energy California LLC *5/21/2012*
HECA Project

Urea Absorber Vents

Operating Hours		8,000	hr/yr			
CO_2		32	lb/hour			
CO_2 =	116	tonne/yr				
CH_4 =		tonne/yr =	0	tonne CO_2e/yr		
N_2O =		tonne/yr =	0	tonne CO_2e/yr	Total tonne CO_2e/yr =	116

Emission rate provided by project engineers.

Nitric Acid Unit

Operating Hours		8,000	hr/yr			
N_2O uncontrolled		6.32	lb/ton NHO3			
Production rate		501	ton/day			
N_2O uncontrolled		132	lb/hour			
destruction efficiency		95	%			
N_2O controlled		6.6	lb/hour			
CO_2 =		tonne/yr				
CH_4 =		tonne/yr =	0	tonne CO_2e/yr		
N_2O =	24	tonne/yr =	7,426	tonne CO_2e/yr	Total tonne CO_2e/yr =	7,426

Emission factor and destruction efficiency provided by design engineer.

230 kV Circuit Breakers

Number of Circuit Breakers		6				
SF_6 capacity		240	lb/breaker			
Annual Leakage rate		0.5%				
SF_6 =	0.003	tonne/yr =	78	tonne CO_2e/yr	Total tonne CO_2e/yr =	78

SF6 GWP = 23,900 http://www.epa.gov/electricpower-sf6/faq.html)
Sources: SF6 inventory and maximum leakage rates from electrical equipment suppliers

18 kV Circuit Breakers

Number of Circuit Breakers		2				
SF_6 capacity		73	lb/breaker			
Annual Leakage rate		0.5%				
SF_6 =	0.000	tonne/yr =	8	tonne CO_2e/yr	Total tonne CO_2e/yr =	8

SF6 GWP = 23,900 http://www.epa.gov/electricpower-sf6/faq.html)
Sources: SF6 inventory and maximum leakage rates from electrical equipment suppliers

Total tonne CO_2e/yr for Stationary Sources=	**535,278**

Gas Composition for the Syngas and PSA Off-gas

Hydrogen Energy California LLC *5/21/2012*
HECA Project

		Greenhouse Gas Fuel Summary and Durations of Major Fuel Consumers											
		Syngas						PSA Off-Gas					
COMPONENTS	MW	mol%	mol*MW (lb/lbmole)	Wt%	MW C	% C	wt%Cmix	mol%	mol*MW (lb/lbmole)	Wt%	MW C	% C	wt%Cmix
CO (CARBON MONOXIDE)	28.01	1.92	0.54	8.48%	12	42.84%	3.63%	9.10	2.55	11.36%	12	42.84%	4.87%
H2 (HYDROGEN)	2.02	83.80	1.69	26.62%	-	0.00%	0.00%	23.78	0.48	2.14%	-	0.00%	0.00%
CO2 (CARBON DIOXIDE)	44.01	1.50	0.66	10.38%	12	27.27%	2.83%	7.09	3.12	13.92%	12	27.27%	3.79%
H2O (WATER)	18.02	-	-	0.00%	-	0.00%	0.00%	-	-	0.00%	-	0.00%	0.00%
CH4 (METHANE)	16.04	1.07	0.17	2.69%	12	74.81%	2.01%	5.03	0.81	3.60%	12	74.81%	2.69%
Ar (ARGON)	39.95	0.13	0.05	0.79%	-	0.00%	0.00%	0.59	0.23	1.04%	-	0.00%	0.00%
N2 (NITROGEN)	28.01	11.58	3.24	51.02%	-	0.00%	0.00%	54.38	15.23	67.90%	-	0.00%	0.00%
H2S (HYDROGEN SULFIDE)	34.08	0.00	0.00	0.00%	-	0.00%	0.00%	0.00	0.00	0.00%	-	0.00%	0.00%
COS (CARBONYL SULFIDE)	60.07	0.00	0.00	0.00%	12	19.98%	0.00%	0.00	0.00	0.00%	12	19.98%	0.00%
CH3OH (METHANOL)	32.03	0.01	0.00	0.03%	12	37.46%	0.01%	0.03	0.01	0.04%	12	37.46%	0.01%
C2H6 (ETHANE)	30.07	-	-	0.00%	24	79.81%	0.00%	-	-	0.00%	24	79.81%	0.00%
C3H8 (PROPANE)	44.10	-	-	0.00%	36	81.63%	0.00%	-	-	0.00%	36	81.63%	0.00%
C4H10 (N-BUTANE)	58.12	-	-	0.00%	48	82.59%	0.00%	-	-	0.00%	48	82.59%	0.00%
C4H10 (ISO-BUTANE)	58.12	-	-	0.00%	48	82.59%	0.00%	-	-	0.00%	48	82.59%	0.00%
C5H12 (N-PENTANE)	72.15	-	-	0.00%	60	83.16%	0.00%	-	-	0.00%	60	83.16%	0.00%
C5H12 (ISO-PENTANE)	72.15	-	-	0.00%	60	83.16%	0.00%	-	-	0.00%	60	83.16%	0.00%
C6+ (HEXANES, ETC)	86.18	-	-	0.00%	72	83.55%	0.00%	-	-	0.00%	72	83.55%	0.00%
NH3 (AMMONIA)	17.04	-	-	0.00%	-	0.00%	0.00%	-	-	0.00%	-	0.00%	0.00%
HCl (HYDROGEN CHLORIDE)	36.48	-	-	0.00%	-	0.00%	0.00%	-	-	0.00%	-	0.00%	0.00%
HCN (HYDROGEN CYANIDE)	27.03	-	-	0.00%	12	44.40%	0.00%	-	-	0.00%	12	44.40%	0.00%
Total		**100.00**	**6.36**	**100.00%**			**8.48%**	**100.00**	**22.43**	**100.00%**			**11.37%**

		Duration (hr)	Fuel input HHV (MMBtu/hr)	fuel consumption (MMscf/hr)	Duration (hr)	Fuel input HHV (MMBtu/hr)	fuel consumption (MMscf/hr)
Gas Turbine	mmBTU/h	8,108	2,536.57	8.79	-	-	
Duct Burner	mmBTU/h	8,000	165.00	0.57	8,000	149.00	0.95
HHV (Btu/scf)		288.6			157.3		
Percentage of destruction of CH4		98.0%			98.0%		
CO2 lb/MMBtu HHV		17.704			153.56		
CH4 lb/MMBtu HHV		0.031			0.27		

		Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)	Annual Emissions (tonnes/yr)	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)	Annual Emissions (tonnes/yr)
CO2 emissions (lb/hr)	Gas Turbine	44,906	182,050	165,200	22,881	91,524	83,053
CH4 emissions (lb/hr)	Gas Turbine	79	321	291	40	161	146
CO2 emissions (lb/hr)	Duct Burner	2,921	11,684	10,603			
CH4 emissions (lb/hr)	Duct Burner	5	21	19			

Notes:
All Data based on Case 5 Performance Avg Ambient On-Peak
Includes startup and shutdown hours in the turbine operations. Assumed max heating value during SU/SD hours.
No startup or shutdown for duct burners

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Greenhouse Gas Emissions Associated with the Mobile Sources During Project Operations

Source	Annual CO2e Emissions (tonne/year)
Onsite Trucks	413
Onsite Trains	291
Offsite Workers Commuting	824
Offsite Trucks	10,866
Offsite Trains	45,226
Total CO2e Annual Emissions	**57,619**

Notes:
Onsite worker travel and associated emissions are negligible

GHG Emissions from Mobile Sources

Hydrogen Energy California LLC *5/21/2012*
HECA Project

GHG emissions are numerically depicted as metric tons (tonne) of carbon dioxide equivalents (CO_2e). CO_2e represents CO_2 plus the additional warming potential from CH_4 and N_2O. CH_4 and N_2O have 21 and 310 times the warming potential of CO_2, respectively.

Onsite LHD Gasoline Trucks

Number of Onsite Trucks		10	trucks		EF CO_2 =	1,175	g/mi
Total Annual VMT		10,000	miles/ truck		EF CH_4 =	0.0157	g/mi
					EF N_2O =	0.0101	g/mi
CO_2 =	118	tonne/yr					
CH_4 =	1.57E-03	tonne/yr =	3.E-02	tonne CO_2e/yr			
N_2O =	1.01E-03	tonne/yr =	3.E-01	tonne CO_2e/yr	Total tonne CO_2e/yr =		118

CO2 emissions from EMFAC2007 for fleet year 2010 for light heavy-duty gasoline trucks travelling at 15 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for light gasoline trucks.

Onsite LHD Diesel Trucks

Number of Onsite Trucks		10	trucks		EF CO_2 =	519	g/mi
Total Annual VMT		10,000	miles/ truck		EF CH_4 =	0.001	g/mi
					EF N_2O =	0.0015	g/mi
CO_2 =	52	tonne/yr					
CH_4 =	1.00E-04	tonne/yr =	2.E-03	tonne CO_2e/yr			
N_2O =	1.50E-04	tonne/yr =	5.E-02	tonne CO_2e/yr	Total tonne CO_2e/yr =		52

CO2 emissions from EMFAC2007 for fleet year 2010 for light heavy-duty diesel trucks travelling at 15 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for light diesel trucks.

Onsite Petcoke Trucks

Number of Truck loads		15,200	truck loads		EF CO_2 =	3,165	g/mi
Distrance Travelled Onsite		1.0	mi/ load		EF CH_4 =	0.0051	g/mi
Truck Idle Time		0.08	hr/load		EF N_2O =	0.0048	g/mi
					EF CO_2 =	6,542	g/ idle hr
					EF CH_4 =	0.011	g/ idle hr
					EF N_2O =	0.010	g/ idle hr
CO_2 =	54	tonne/yr					
CH_4 =	8.75E-05	tonne/yr =	2.E-03	tonne CO_2e/yr			
N_2O =	8.23E-05	tonne/yr =	3.E-02	tonne CO_2e/yr	Total tonne CO_2e/yr =		54

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 10 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles. Idling emission Factor for N2O and CH4 were extrapolated based on the ratio of CO2 emission factor for running vs idling.

Onsite Product Trucks

Number of Truck loads		20,880	truck loads		EF CO_2 =	3,165	g/mi
Distrance Travelled Onsite		2.49	mi/ load		EF CH_4 =	0.0051	g/mi
Truck Idle Time		0.08	hr/load		EF N_2O =	0.0048	g/mi
					EF CO_2 =	6,542	g/ idle hr
					EF CH_4 =	0.011	g/ idle hr
					EF N_2O =	0.010	g/ idle hr
CO_2 =	176	tonne/yr					
CH_4 =	2.83E-04	tonne/yr =	6.E-03	tonne CO_2e/yr			
N_2O =	2.66E-04	tonne/yr =	8.E-02	tonne CO_2e/yr	Total tonne CO_2e/yr =		176

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 10 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles. Idling emission Factor for N2O and CH4 were extrapolated based on the ratio of CO2 emission factor for running vs idling.

GHG Emissions from Mobile Sources

Hydrogen Energy California LLC *5/21/2012*
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Onsite Miscellaneous Diesel Trucks

Number of Truck loads		1,818	truck loads		EF CO_2 =	3,165	g/mi
Distrance Travelled Onsite		2.2	mi/ load		EF CH_4 =	0.0051	g/mi
					EF N_2O =	0.0048	g/mi
CO_2 =	13	tonne/yr					
CH_4 =	2.04E-05	tonne/yr =	4.E-04	tonne CO_2e/yr			
N_2O =	1.92E-05	tonne/yr =	6.E-03	tonne CO_2e/yr	Total tonne CO_2e/yr =		13

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 10 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles.

Onsite Switching Engines

Number of engines		1	per year		EF CO_2 =	672	g/bhp-hr
Avg power used onsite		260	hp		EF CH_4 =	0.053	g/bhp-hr
Annual operations		1248	hours/yr		EF N_2O =	0.0171	g/bhp-hr
CO_2 =	218	tonne/yr					
CH_4 =	1.71E-02	tonne/yr =	4.E-01	tonne CO_2e/yr			
N_2O =	5.55E-03	tonne/yr =	2.E+00	tonne CO_2e/yr	Total tonne CO_2e/yr =		220

New engines will meet Tier 3 emissions (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH4 and N2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for locomotives.

Onsite Coal Trains

Number of Trains		109	per year		EF CO_2 =	491	g/bhp-hr
Number of engines		218	per year		EF CH_4 =	0.038	g/bhp-hr
Avg power used onsite		220	hp		EF N_2O =	0.0125	g/bhp-hr
Time to unload each train		2	hours				
CO_2 =	47	tonne/yr					
CH_4 =	3.69E-03	tonne/yr =	8.E-02	tonne CO_2e/yr			
N_2O =	1.20E-03	tonne/yr =	4.E-01	tonne CO_2e/yr	Total tonne CO_2e/yr =		48

New engines will meet Tier 3 emissions (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH4 and N2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for locomotives.

Onsite Product Trains

Number of Trains		153	per year		EF CO_2 =	491	g/bhp-hr
Number of engines		153	per year		EF CH_4 =	0.038	g/bhp-hr
Avg power used onsite		150	hp		EF N_2O =	0.0125	g/bhp-hr
Time to unload each train		2	hours				
CO_2 =	23	tonne/yr					
CH_4 =	1.77E-03	tonne/yr =	4.E-02	tonne CO_2e/yr			
N_2O =	5.74E-04	tonne/yr =	2.E-01	tonne CO_2e/yr	Total tonne CO_2e/yr =		23

New engines will meet Tier 3 emissions (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH4 and N2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for locomotives.

Offsite Coal Trains

Number of Trains cars per year		13,034	per year		EF CO_2 =	10,217	g/gal
Miles Traveled Per Train		794	Miles one way		EF CH_4 =	0.8	g/gal
Rail Freight Fuel Consumption		480	ton-mile/gallon		EF N_2O =	0.26	g/gal
Loaded train car weight		142	ton				
Unloaded train car weight		25	ton				
All Trains - Round Trip		1.73E+09	ton-miles/year				
Fuel Use for all Trains - Round Trip		3,600,461	gal/year				
CO_2 =	36,786	tonne/yr					
CH_4 =	2.88	tonne/yr =	60.49	tonne CO_2e/yr			
N_2O =	0.94	tonne/yr =	290.20	tonne CO_2e/yr	Total tonne CO_2e/yr =		37,137

New engines will meet Tier 3 emissions (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH4 and N2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for locomotives.

GHG Emissions from Mobile Sources

Hydrogen Energy California LLC *5/21/2012*
HECA Project

Offsite Liquid Sulfur Product Trains

Number of Trains cars per year		83	per year		EF CO_2 =	10,217	g/gal
Miles Traveled Per Train		150	Miles one way		EF CH_4 =	0.8	g/gal
Rail Freight Fuel Consumption		480	ton-mile/gallon		EF N_2O =	0.26	g/gal
Loaded train car weight		125	ton				
Unloaded train car weight		25	ton				
All Trains - Round Trip		1.87E+06	ton-miles/year				
Fuel Use for all Trains - Round Trip		3,890	gal/year				
CO_2 =	39.75	tonne/yr					
CH_4 =	3.11E-03	tonne/yr =	7.E-02	tonne CO_2e/yr			
N_2O =	1.01E-03	tonne/yr =	3.E-01	tonne CO_2e/yr	Total tonne CO_2e/yr =		40

New engines will meet Tier 3 emissions (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH4 and N2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for locomotives.

Offsite Gasification Solid Product Trains

Number of Trains cars per year		2,800	per year		EF CO_2 =	10,217	g/gal
Miles Traveled Per Train		198	Miles one way		EF CH_4 =	0.8	g/gal
Rail Freight Fuel Consumption		480	ton-mile/gallon		EF N_2O =	0.26	g/gal
Loaded train car weight		125	ton				
Unloaded train car weight		25	ton				
All Trains - Round Trip		8.32E+07	ton-miles/year				
Fuel Use for all Trains - Round Trip		173,244	gal/year				
CO_2 =	1,770	tonne/yr					
CH_4 =	1.39E-01	tonne/yr =	3.E+00	tonne CO_2e/yr			
N_2O =	4.50E-02	tonne/yr =	1.E+01	tonne CO_2e/yr	Total tonne CO_2e/yr =		1,787

New engines will meet Tier 3 emissions (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH4 and N2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for locomotives.

Offsite Ammonia Product Trains

Number of Trains cars per year		357	per year		EF CO_2 =	10,217	g/gal
Miles Traveled Per Train		264	Miles one way		EF CH_4 =	0.8	g/gal
Rail Freight Fuel Consumption		480	ton-mile/gallon		EF N_2O =	0.26	g/gal
Loaded train car weight		142	ton				
Unloaded train car weight		25	ton				
All Trains - Round Trip		1.57E+07	ton-miles/year				
Fuel Use for all Trains - Round Trip		32,789	gal/year				
CO_2 =	335	tonne/yr					
CH_4 =	2.62E-02	tonne/yr =	6.E-01	tonne CO_2e/yr			
N_2O =	8.53E-03	tonne/yr =	3.E+00	tonne CO_2e/yr	Total tonne CO_2e/yr =		338

New engines will meet Tier 3 emissions (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH4 and N2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for locomotives.

Offsite Urea Product Trains

Number of Trains cars per year		1,795	per year		EF CO_2 =	10,217	g/gal
Miles Traveled Per Train		628	Miles one way		EF CH_4 =	0.8	g/gal
Rail Freight Fuel Consumption		480	ton-mile/gallon		EF N_2O =	0.26	g/gal
Loaded train car weight		142	ton				
Unloaded train car weight		25	ton				
All Trains - Round Trip		1.88E+08	ton-miles/year				
Fuel Use for all Trains - Round Trip		392,179	gal/year				
CO_2 =	4,007	tonne/yr					
CH_4 =	3.14E-01	tonne/yr =	7.E+00	tonne CO_2e/yr			
N_2O =	1.02E-01	tonne/yr =	3.E+01	tonne CO_2e/yr	Total tonne CO_2e/yr =		4,045

New engines will meet Tier 3 emissions (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH4 and N2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for locomotives.

GHG Emissions from Mobile Sources

Hydrogen Energy California LLC *5/21/2012*
HECA Project

Offsite UAN Product Trains

Number of Trains cars per year		1,983	per year		EF CO_2 =	10,217	g/gal
Miles Traveled Per Train		264	Miles one way		EF CH_4 =	0.8	g/gal
Rail Freight Fuel Consumption		480	ton-mile/gallon		EF N_2O =	0.26	g/gal
Loaded train car weight		142	ton				
Unloaded train car weight		25	ton				
All Trains - Round Trip		8.74E+07	ton-miles/year				
Fuel Use for all Trains - Round Trip		182,132	gal/year				
CO_2 =	1,861	tonne/yr					
CH_4 =	1.46E-01	tonne/yr =	3.E+00	tonne CO_2e/yr			
N_2O =	4.74E-02	tonne/yr =	1.E+01	tonne CO_2e/yr	Total tonne CO_2e/yr =		1,879

New engines will meet Tier 3 emissions (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH4 and N2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) for locomotives.

Offsite Petcoke Trucks

Number of Trucks		15,200	truck per year		EF CO_2 =	1,671	g/mi
Distance traveled per Truck (Round Trip)		280	miles/ truck		EF CH_4 =	0.0051	g/mi
Total Annual VMT		4,256,000	miles/ year		EF N_2O =	0.0048	g/mi
CO_2 =	7,110	tonne/yr					
CH_4 =	2.17E-02	tonne/yr =	5.E-01	tonne CO_2e/yr			
N_2O =	2.04E-02	tonne/yr =	6.E+00	tonne CO_2e/yr	Total tonne CO_2e/yr =		7,117

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 50 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles. Idling emission Factor for N2O and CH4 were extrapolated based on the ratio of CO2 emission factor for running vs idling.

Offsite Liquid Sulfur Product Trucks

Number of Trucks		990	truck per year		EF CO_2 =	1,671	g/mi
Distance traveled per Truck (Round Trip)		284	miles/ truck		EF CH_4 =	0.0051	g/mi
Total Annual VMT		281,160	miles/ year		EF N_2O =	0.0048	g/mi
CO_2 =	470	tonne/yr					
CH_4 =	1.43E-03	tonne/yr =	3.E-02	tonne CO_2e/yr			
N_2O =	1.35E-03	tonne/yr =	4.E-01	tonne CO_2e/yr	Total tonne CO_2e/yr =		470

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 50 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles. Idling emission Factor for N2O and CH4 were extrapolated based on the ratio of CO2 emission factor for running vs idling.

Offsite Gasification Solids Product Trucks

Number of Trucks		2,800	truck per year		EF CO_2 =	1,671	g/mi
Distance traveled per Truck (Round Trip)		160	miles/ truck		EF CH_4 =	0.0051	g/mi
Total Annual VMT		448,000	miles/ year		EF N_2O =	0.0048	g/mi
CO_2 =	748	tonne/yr					
CH_4 =	2.28E-03	tonne/yr =	5.E-02	tonne CO_2e/yr			
N_2O =	2.15E-03	tonne/yr =	7.E-01	tonne CO_2e/yr	Total tonne CO_2e/yr =		749

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 50 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles. Idling emission Factor for N2O and CH4 were extrapolated based on the ratio of CO2 emission factor for running vs idling.

GHG Emissions from Mobile Sources

Hydrogen Energy California LLC *5/21/2012*
HECA Project

Offsite Ammonia Product Trucks

Number of Trucks		5,010	truck per year		EF CO_2 =	1,671	g/mi
Distance traveled per Truck (Round Trip)		80	miles/ truck		EF CH_4 =	0.0051	g/mi
Total Annual VMT		400,800	miles/ year		EF N_2O =	0.0048	g/mi
CO_2 =	670	tonne/yr					
CH_4 =	2.04E-03	tonne/yr =	4.E-02	tonne CO_2e/yr			
N_2O =	1.92E-03	tonne/yr =	6.E-01	tonne CO_2e/yr	Total tonne CO_2e/yr =		670

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 50 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles. Idling emission Factor for N2O and CH4 were extrapolated based on the ratio of CO2 emission factor for running vs idling.

Offsite Urea Product Trucks

Number of Trucks		2,800	truck per year		EF CO_2 =	1,671	g/mi
Distance traveled per Truck (Round Trip)		80	miles/ truck		EF CH_4 =	0.0051	g/mi
Total Annual VMT		224,000	miles/ year		EF N_2O =	0.0048	g/mi
CO_2 =	374	tonne/yr					
CH_4 =	1.14E-03	tonne/yr =	2.E-02	tonne CO_2e/yr			
N_2O =	1.08E-03	tonne/yr =	3.E-01	tonne CO_2e/yr	Total tonne CO_2e/yr =		375

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 50 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles. Idling emission Factor for N2O and CH4 were extrapolated based on the ratio of CO2 emission factor for running vs idling.

Offsite UAN Product Trucks

Number of Trucks		9,280	truck per year		EF CO_2 =	1,671	g/mi
Distance traveled per Truck (Round Trip)		80	miles/ truck		EF CH_4 =	0.0051	g/mi
Total Annual VMT		742,400	miles/ year		EF N_2O =	0.0048	g/mi
CO_2 =	1,240	tonne/yr					
CH_4 =	3.79E-03	tonne/yr =	8.E-02	tonne CO_2e/yr			
N_2O =	3.56E-03	tonne/yr =	1.E+00	tonne CO_2e/yr	Total tonne CO_2e/yr =		1,241

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 50 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles. Idling emission Factor for N2O and CH4 were extrapolated based on the ratio of CO2 emission factor for running vs idling.

Offsite Equipment and Miscellaneous Trucks

Number of Trucks		1,818	truck per year		EF CO_2 =	1,671	g/mi
Distance traveled per Truck (Round Trip)		80	miles/ truck		EF CH_4 =	0.0051	g/mi
Total Annual VMT		145,440	miles/ year		EF N_2O =	0.0048	g/mi
CO_2 =	243	tonne/yr					
CH_4 =	7.42E-04	tonne/yr =	2.E-02	tonne CO_2e/yr			
N_2O =	6.98E-04	tonne/yr =	2.E-01	tonne CO_2e/yr	Total tonne CO_2e/yr =		243

CO2 emissions from EMFAC2007 for fleet year 2010 heavy-heavy duty diesel trucks travelling at 50 mph. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for diesel heavy duty vehicles. Idling emission Factor for N2O and CH4 were extrapolated based on the ratio of CO2 emission factor for running vs idling.

GHG Emissions from Mobile Sources

Hydrogen Energy California LLC *5/21/2012*
HECA Project

Offsite Employee Commute Vehicles

Total Number of Employee		200	employees/day		EF CO_2 =	364	g/mi
Number of Worker per Commuter Vehicle		1.3			EF CH_4 =	0.0159	g/mi
Daily Vehicle Count		154	vehicles/day		EF N_2O =	0.0093	g/mi
Distance traveled per vehicle (Round Trip)		40	miles/ vehicle/ day				
Day of Commute per Month		365	days/yr				
Total Annual VMT		2,246,154	miles/year				
CO_2 =	817	tonne/yr				
CH_4 =	3.57E-02	tonne/yr =	7.E-01	tonne CO_2e/yr		
N_2O =	2.09E-02	tonne/yr =	6.E+00	tonne CO_2e/yr	Total tonne CO_2e/yr =	824

CO2 emission factor for CO2 is from EMFAC 2007 (average of light duty automobile and light duty truck) for the vehicle model year fro m1971 to 2015. Running emission Factor for N2O and CH4 is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for average of gasoline passenger cars, gasoline light trucks, diesel passenger cars, and diesel light truck.

Total tonne CO_2e/yr for Mobile Sources=	**57,619**

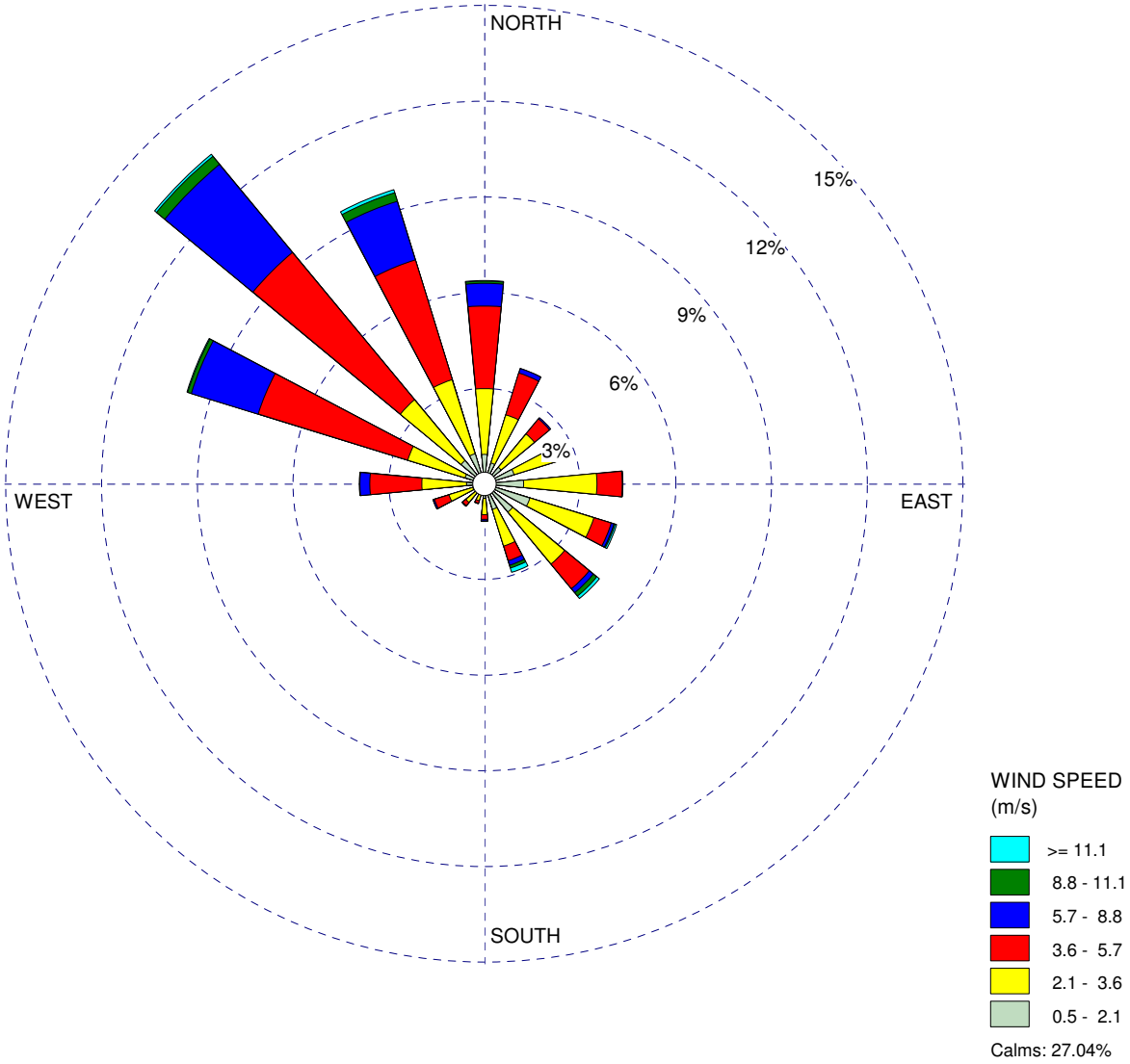
Appendix H

Seasonal and Annual Wind Roses

WIND ROSE PLOT:

Bakersfield Meadows Field Airport 2006-2010
SJVAPCD Processed, March 2012

DISPLAY:
Wind Speed
Direction (blowing from)



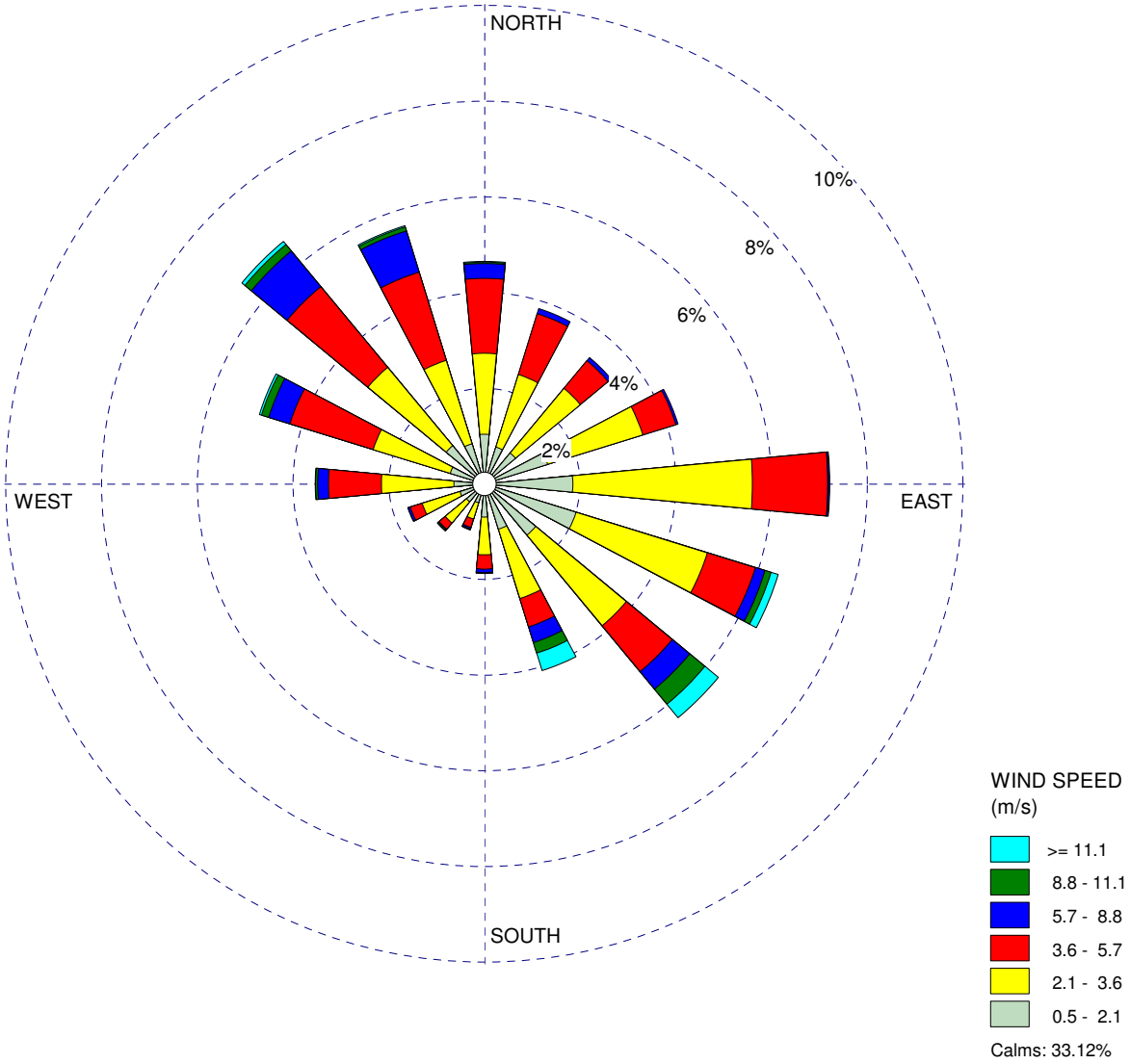
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	Start Date: 1/1/2006 - 00:00 **End Date: 12/31/2010 - 23:00**	**URS**	
		MODELER: **LMB**	
	CALM WINDS: **27.04%**	TOTAL COUNT: **43746 hrs.**	
	AVG. WIND SPEED: **2.91 m/s**	DATE: **3/8/2012**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Bakersfield Meadows Field Airport 2006-2010
SJVAPCD Processed, March 2012

DISPLAY:
Wind Speed
Direction (blowing from)



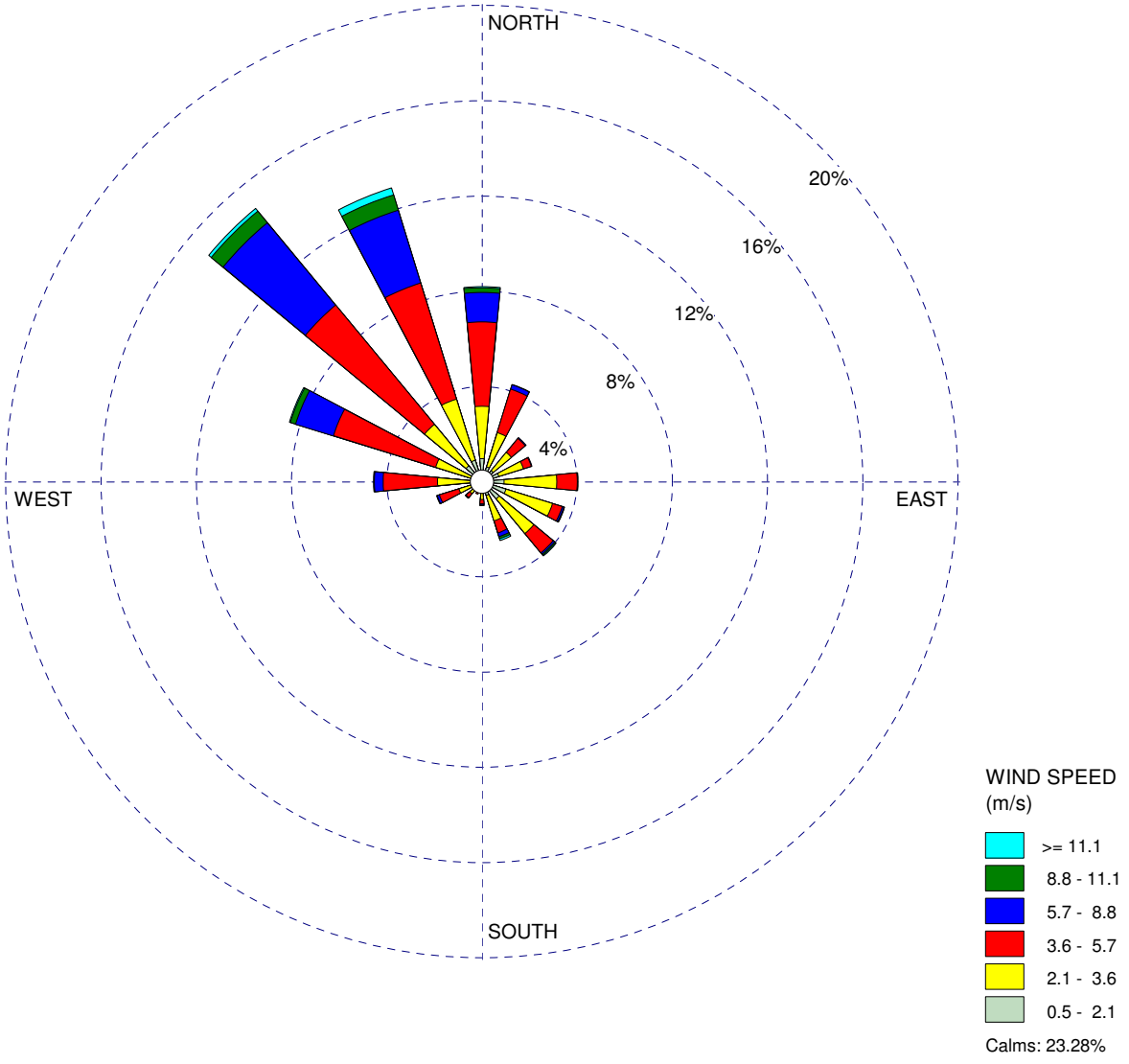
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Winter Season	**Start Date: 1/1/2006 - 00:00** **End Date: 12/31/2010 - 23:00**	**URS**	
		MODELER: **LMB**	
	CALM WINDS: **33.12%**	TOTAL COUNT: **10790 hrs.**	
	AVG. WIND SPEED: **2.42 m/s**	DATE: **4/9/2012**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Bakersfield Meadows Field Airport 2006-2010
SJVAPCD Processed, March 2012

DISPLAY:
Wind Speed
Direction (blowing from)



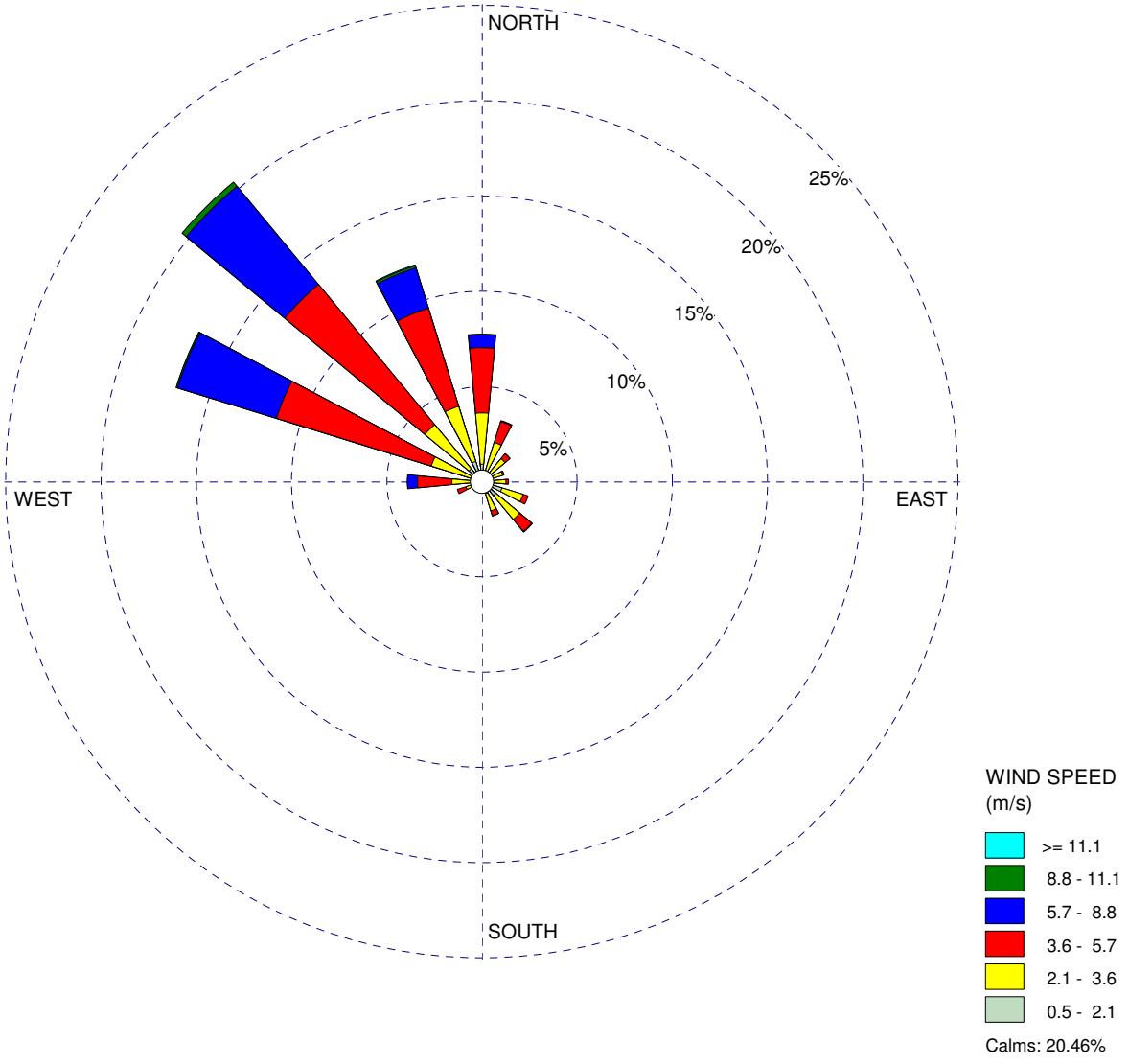
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Spring Season	**Start Date: 3/1/2006 - 00:00** **End Date: 5/31/2010 - 23:00**	**URS**	
		MODELER: **LMB**	
	CALM WINDS: **23.28%**	TOTAL COUNT: **11024 hrs.**	
	AVG. WIND SPEED: **3.28 m/s**	DATE: **4/9/2012**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Bakersfield Meadows Field Airport 2006-2010
SJVAPCD Processed, March 2012

DISPLAY:
Wind Speed
Direction (blowing from)



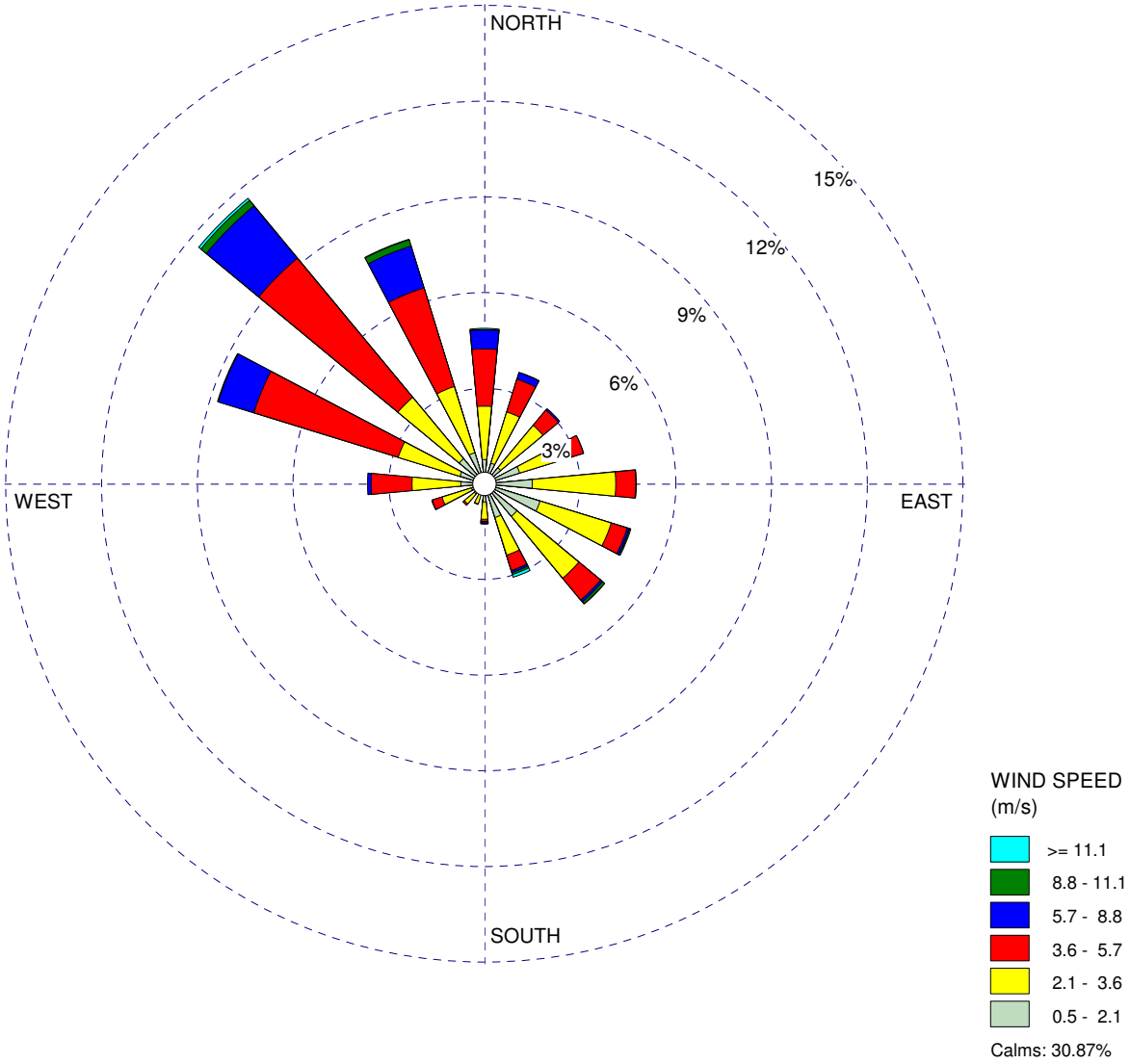
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Summer Season	**Start Date: 6/1/2006 - 00:00** **End Date: 8/31/2010 - 23:00**	**URS**	
		MODELER: **LMB**	
	CALM WINDS: **20.46%**	TOTAL COUNT: **11003 hrs.**	
	AVG. WIND SPEED: **3.40 m/s**	DATE: **4/9/2012**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Bakersfield Meadows Field Airport 2006-2010
SJVAPCD Processed, March 2012

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Fall Season	**Start Date: 9/1/2006 - 00:00** **End Date: 11/30/2010 - 23:00**	**URS**	
		MODELER: **LMB**	
	CALM WINDS: **30.87%**	TOTAL COUNT: **10905 hrs.**	
	AVG. WIND SPEED: **2.53 m/s**	DATE: **4/9/2012**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Appendix I

NO_2 1-Hour Regional Analysis

MODELING REPORT FOR

1-HOUR NO_2 NAAQS REGIONAL MODELING

FOR THE HYDROGEN ENERGY CALIFORNIA (HECA) PROJECT

Prepared for:

U.S. Environmental Protection Agency Region IX

San Joaquin Valley Air Pollution Control District

California Energy Commission

Prepared on behalf of:

Hydrogen Energy California LLC

April 2012

URS

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Attachments

Attachment A. HECA Nearby Sources to 75 km included in the Regional Modeling Analysis

Attachment B. SJVAPCD, Permit Services Department. Villalvazo, Leland and Ester Davila. *Procedures for Downloading and Processing NCDC Meteorological Data.* May 2010.

Attachment C. CAPCOA, *Modeling Compliance of the Federal 1-Hour NO_2 NAAQS, Appendix C, In-Stack NO_2/NO_X Ratios*, October 2011.

1. INTRODUCTION

On January 22, 2010, the United States Environmental Protection Agency (USEPA) announced a new primary nitrogen dioxide (NO_2) 1-hour National Ambient Air Quality Standard (NAAQS). The standard is attained when the 3-year average of the 98th percentile of the annual distribution of the daily maximum 1-hour concentrations does not exceed 100 parts per billion (ppb). This new standard will apply to the Hydrogen Energy California (HECA) Project.

In February 2010, the USEPA issued *Notice Regarding Modeling for New Hourly NO_2 NAAQS* (USEPA, 2010b). In June 2010, the USEPA issued a compliance guidance document, *Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program* (USEPA, 2010c). These guidance documents include a description of Tier 3 "detailed screening methods" for modeling compliance with the 1-hour NO_2 federal standard.

In preparation for conducting the regional NO_2 modeling analysis described in the guidance document, HECA sought concurrence from USEPA Region IX and from the USEPA Office of Air Quality Planning and Standards (OAQPS) through submittal of a protocol document entitled "*Modeling Protocol for Parameter Selection Specific to the 1 Hour NO_2 NAAQS Regional Modeling for the Hydrogen Energy California (HECA) Project*" dated January 20, 2011 (referred to as the "January 2011 protocol"). The January 2011 protocol proposed source screening methodology and input parameters for the HECA Project's regional NO_2 modeling analysis. The January 2011 protocol document received approval from both USEPA Region IX and the OAQPS on March 11, 2011. This document describes and presents the results of the Tier 3 "detailed screening methods" modeling analysis performed to satisfy the 1-hour NO_2 federal standard.

In March 2011, the USEPA issued an additional guidance document: *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (USEPA, 2011). This guidance, hereafter referred to as the "March 2011 USEPA Memo," provided further clarification on uncertainties raised since the earlier USEPA June 2010 modeling guidance document. Because this document was released after the HECA Project's submittal of the January 2011 protocol document, HECA prepared the *Modeling Protocol Supplement for the Hydrogen Energy California (HECA) Project*, February 2012, outlining any variances in modeling techniques from the January 2011 protocol.

1.1 PROJECT DESCRIPTION

Hydrogen Energy California LLC (HECA) is proposing an Integrated Gasification Combined Cycle (IGCC) polygeneration project (hereafter referred to as HECA or the Project). The Project will gasify a 75 percent coal and 25 percent petroleum coke (petcoke) fuel blend to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel and used to generate a nominal 300-megawatt (MW) output of low-carbon baseload electricity in a Combined Cycle Power Block, and to produce low-carbon nitrogen-based products in an integrated Manufacturing Complex. Carbon dioxide (CO_2) from the HECA facility will be captured and transported to the adjacent Elk Hills Oil Field (EHOF) for use in enhanced oil

recovery (EOR), which results in sequestration (storage) of the CO_2. Occidental of Elk Hills Incorporated (OEHI) will use the CO_2 for EOR at the EHOF.

The HECA Project is approximately 7 miles west of the outermost edge of the city of Bakersfield and 1.5 miles northwest of the unincorporated community of Tupman in western Kern County, California. Figure 1 presents an overview map of the HECA Project location, as well as the locations of regional monitoring stations in relation to the HECA Project. Figure 2 presents close-up aerial images of the HECA Project Site next to the surface meteorological station. The HECA Project is within the San Joaquin Valley Air Basin and is within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SJVAPCD). The Project area is in attainment for NO_2, and therefore HECA is subject to Prevention of Significant Deterioration (PSD) requirements. Since annual HECA emissions are greater than the NO_2 PSD Significant Emission Rate (SER) of 40 tons/yr, HECA must conduct modeling for compliance with the NO_2 1-hour NAAQS.

This introduction provides a brief description of the HECA Project. Additional details are provided in the AFC Amendment (2012), Section 2.0, Project Description.

2. OVERALL MODELING APPROACH

This section outlines the overall modeling approach that was undertaken by the HECA Project to show compliance with the new 1-hour NO_2 NAAQS. Subsequent sections describe the details of individual parameters that were included in the modeling analysis.

The new 1-hour NO_2 NAAQS is 100 ppb (or 188.68 micrograms per cubic meter [$\mu g/m^3$]). The NAAQS is a statistical standard based on the 3-year average of the annual 98th percentile of the daily maximum 1-hour concentrations.

Modeling was conducted per the techniques described in the HECA January 2011 protocol and February 2012 protocol supplement. In addition HECA conducted the NO_2 1-hour NAAQS analysis incorporating guidance from the March 2011 USEPA Memo, the USEPA June 2010 modeling guidance, CAPCOA *Modeling Compliance of The Federal 1-Hour NO_2 NAAQS*, October 2011, and SJVAPCD *Assessment of Non-Regulatory Option in AERMOD Specifically OLM and PVMRM*, September 2010.

The American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) version 12060 was used to estimate the 1-hour ground level concentrations of NO_2. The model has received a scientific peer review. As noted in the USEPA's June 2010 guidance document, AERMOD is the preferred model for dispersion for a wide range of applications.

To address NO_X chemistry, the ozone-limiting method (OLM) plume volume molar ratio method (PVMRM) algorithm was used in AERMOD, which is explained in detail later. The AERMOD model was run using the rural dispersion setting.

The first step of the NO_2 1-hour analysis was to model the HECA sources alone to determine if the multiyear average first high 1-hour concentrations at every receptor within 50 kilometers are less than the interim Significant Impact Level (SIL) of 4 ppb. Modeling showed concentrations

greater than or equal to the SIL at receptors out approximately 13 kilometers, which is the Area of Impact (AOI).

Because the Project's impacts exceeded the SIL at several receptors based on this initial impact analysis, a cumulative (or regional) impact assessment was completed to determine whether the project would cause or contribute to any modeled violations of the NAAQS.

The cumulative analysis was completed including emissions from HECA sources, nearby sources, and background concentrations measured at a nearby monitoring station. Only receptors that were shown to have Project impacts greater than or equal to the SIL were included in the cumulative modeling.

Modeled concentrations from HECA and regional emissions sources were added to hourly background monitoring NO_2 data to determine the cumulative average 98th percentile maximum daily 1-hour impacts for all ranks below the 98th percentile until the NAAQS was no longer exceeded. In AERMOD, the design value is calculated as the eighth-highest (98th percentile) daily maximum 1-hour concentration averaged across the 5 modeled years at each receptor.

The MAXDCONT option in AERMOD was run to determine the NO_2 1-hour impact contribution from HECA. The option was run from rank 8 (or the 98th percentile daily maximum value per receptor averaged over 5 years) to rank 20, with a threshold value equal to the NO_2 1-hour NAAQS (188 $\mu g/m^3$). The target source group was set to all sources (HECA, regional sources, and background). This setup option continues to examine the concentrations for all ranks until the impacts from all sources are less than the threshold value of 188 $\mu g/m^3$. This option was used to determine if there are any exceedances of the NAAQS from all sources and, if an exceedance occurs, to determine whether HECA's contribution is greater than or equal to the SIL at that point in time and space.

If the total regional impacts (i.e., model result plus background) were predicted to be less than the NAAQS, then compliance with the NAAQS was shown. However, if the total regional impacts were predicted to be greater than the NAAQS, then for that hour and receptor, the impact from HECA Project operations sources was compared to the interim SIL. If the predicted impact from just the HECA sources was less than the interim SIL, then it could be concluded that the HECA Project does not contribute to the violation, and thus, compliance with the standard was demonstrated.

2.1 THE PLUME VOLUME MOLAR RATIO METHOD (PVMRM)

The PVMRM algorithm within AERMOD was the OLM used in the modeling analysis. PVMRM accounts for the role of ambient ozone (O_3) in limiting the conversion of emitted NO_X—which occurs mostly in the form of nitrogen oxides (NO)—to NO_2, the pollutant regulated by ambient standards.

The chemistry for PVMRM has been peer-reviewed, as noted by the documents posted on the USEPA's Support Center for Regulatory Air Modeling web site. The posted documents include *Sensitivity Analysis of PVMRM and OLM in AERMOD* (MACTEC, 2004) and *Evaluation of Bias in AERMOD-PVMRM* (MACTEC, 2005). Both documents indicate that the models appear to perform as expected.

The PVMRM algorithm has been demonstrated to be applicable for calculating NO_X chemistry on a theoretical basis. As noted in *Sensitivity Analysis of PVMRM and OLM in AERMOD* (MACTEC, 2004), which was prepared by Roger W. Brode of MACTEC (now with USEPA OAQPS):

> *"Overall the PVMRM option appears to provide a more realistic treatment of the conversion of NO_X to NO_2 as a function of distance downwind from the source than OLM or the other NO_2 screening options (Hanrahan, 1999a; Hanrahan, 1999b). No anomalous behavior of the PVMRM or OLM options was identified as a result of these sensitivity tests."*

Based on this report, the model appears to appropriately account for NO_2 formation and provides a better estimation of the NO_2 impacts, compared to other screening options.

As noted in *Evaluation of Bias in AERMOD-PVMRM* (MACTEC, 2005), which was prepared by Roger W. Brode, PVMRM has been judged to provide unbiased estimates based on criteria that are comparable to, or more rigorous than, evaluations performed for other dispersion models.

The data obtained to conduct the PVMRM run for the HECA Project were: (1) hourly meteorological data, (2) hourly O_3 data, and (3) in-stack NO_2/NO_X ratio. Further refinement of the modeling entailed use of hourly ambient NO_2 data (discussed later). SJVAPCD processed the meteorological, O_3, and NO_2 data following applicable USEPA guidance, as discussed in Section 3. The analysis used NO_2/NO_X in-stack ratios obtained from published references or engineering estimates.

2.2 RECEPTOR DESCRIPTION

USEPA considers most steady-state Gaussian plume models, including AERMOD, to be applicable out to 50 kilometers, but not beyond. Therefore, impacts from the HECA Project operations and nearby sources were examined out to a distance of 50 kilometers from the HECA Project Site in the initial impact analysis. Preliminary modeling with receptors out to 50 kilometers showed that potential impacts from HECA Project operations would generally fall below the interim SIL within 15 kilometers of the HECA Project Site. Although the receptor grid ended at 50 kilometers, large sources located beyond 50 kilometers were included in the nearby source inventory.

The same receptor grid used in the air quality impact analyses presented in the AFC Amendment (2012) was used out to 10 kilometers, with additional receptors out to 50 kilometers. The Project Site is located within the Controlled Area and the property line extends around the outside of the Controlled Area. The receptor grid used in the SIL modeling analysis is as follows:

- 25-meter spacing along the property line and extending from the property line out 100 meters;
- 50-meter spacing from 100 to 250 meters beyond the property line;
- 100-meter spacing from 250 to 500 meters beyond the property line;
- 250-meter spacing from 500 meters to 1 kilometer beyond the property line;
- 500-meter spacing from 1 to 2 kilometers beyond the property line; and
- 1,000-meter spacing from 2 to 50 kilometers beyond the property line.

Terrain heights at receptor grid points were determined from U.S. Geological Survey (USGS) digital national elevation datum (NED) files using AERMAP.

2.3 BUILDING DOWNWASH AND GOOD ENGINEERING PRACTICE STACK HEIGHTS

The effects of building wakes (i.e., downwash) on plumes from the Project's operational sources were evaluated in accordance with USEPA guidance (USEPA, 1985). The USEPA Building Profile Input Program – Prime (BPIP-Prime) (Version 04274) was used to determine data on the buildings on the Project Site that could potentially cause plume downwash effects for different wind directions.

As defined in *Guideline for Determination of Good Engineering Practice Stack Height* (USEPA, 1985), good engineering practice (GEP) is the height necessary to ensure that emissions from a stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles.

All stacks in the HECA Project will be less than or equal to the GEP default height of 65 meters, except for the coal dryer, the three flares, and the CO_2 vent. The CO_2 vent is not a NO_X emission source; therefore, it was not included in this modeling. The height of the coal dryer stack is 92.9 meters, and the height of all three flare stacks (SRU, Gasification and Rectisol) is 76.2 meters.

BPIP Prime has been run to determine the GEP height for each stack. The output of this model shows that the GEP for the three flares is 65 meters, and for the coal dryer is 223.91 meters. BPIP files are provided with this application.

GEP is calculated based on the following equation:

$$Hg = H + 1.5 * L$$

Where: Hg = GEP stack height (in meters)
H = height of the nearby structure (in meters)
L = lesser dimension of the height or projected width of the nearby structure (in meters)

The largest structure near these stacks is the gasifier building, which is 92.9 meters high, 27.7 meters long, and 83 meters wide. Therefore, L = 87.3 meters, H = 92.9 meters, and Hg = 223.9 meters.

The gasifier building is located at a distance within five times L (436.5 meters) from the coal dryer; therefore, GEP for this source is calculated based on the gasifier building dimensions. The height of the coal dryer is well below the GEP height of 223.9 meters.

The flares are located upwind of the gasification building along its shorter axis, thus L = 27.7 meters and Hg = 134.5 meters. The flares are not within 5 times L (138.5 meters) of the gasification structure or any other structure that is large enough to create downwash for the flares in BPIP Prime. It is important to note that the flares will be built to a height of 76.2 meters for safety from a project engineering perspective. However, a 65 meter stack height, or GEP, was

used to calculate effective stack heights for each flare modeling scenario based on the flare's heat release rate during that modeling scenario. The effective stack height is the height of the stack plus the height above the stack where the flare flame ends and a plume can begin. The effective stack parameters were calculated using the SCREEN3 technique, and were input into the AERMOD model (USEPA, 1995b). Therefore, the lower 65 meter stack height was used as the stack height in the calculation of the effective stack heights for the flares, rather than the actual stack height. Appendix E-3, Operational Criteria Pollutant Emissions, of the AFC Amendment (2012), presents the calculation of the effective stack parameters for the flares.

The results of the BPIP-Prime analysis were included in the AERMOD input files to enable downwash effects to be simulated. Input and output files for the BPIP-Prime analyses are included in the electronic files submitted with the AFC Amendment (2012).

2.4 TEMPORAL PAIRING

To estimate the total NO_2 concentration, modeling included HECA sources, nearby sources and background NO_2 data. Background data encompass emission sources not specifically modeled, such as mobile sources.

The 1-hour NO_2 NAAQS was developed for monitoring to allow for the elimination of outlier hours with high monitored concentrations which may not accurately reflect typical conditions near the monitoring station. In order to conduct modeling to comply with this standard, the March 2011 USEPA Memo recommends running AERMOD with the MAXDCONT output option to examine the contribution from the Project emissions to the cumulative impacts at each receptor paired in time and space. AERMOD adds the hourly modeled NO_2 concentrations to the concurrent hourly NO_2 background data, and determines the design value, the eighth-highest (98th percentile) daily maximum 1-hour NO_2 concentration at each receptor averaged across the 5 modeled years.

MAXDCONT was run with the threshold option to output the 8th (design value) through 20th daily maximum 1-hour NO_2 concentrations from all sources including background to ensure the cumulative impact was below the NAAQS. MAXDCONT also presents the contribution from each source at each receptor, paired in time and space if the NAAWS threshold is met. This use of AERMOD and MAXDCONT will provide modeling results that comply with the statistical nature of the NO_2 1-hour NAAQS.

The standard is based on the 98th percentile (eighth-highest) daily maximum 1-hour concentration; as a result, more than one hourly average concentration above the standard on the same day will only result in one concentration greater than the standard for that day. This allows a monitor or model receptor to have 8 hours or more with concentrations greater than the standard on an annual basis, yet to still be considered in compliance as long as there are fewer than 8 days with a daily maximum 1-hour concentration above the standard. The hourly monitoring concentration was greater than or equal to 100 ppb twice during the 5-year data set (2006-2010), but because the standard is based on the eighth-highest daily maximum 1-hour concentration, compliance was able to be shown even with these high outliers.

During the 5-year monitoring period selected for the HECA Project (2006-2010), the NO_2 1-hour monitoring yielded concentrations greater than the standard. The "first tier" assumption (a term

defined in the June 2010 USEPA guidance document [USEPA, 2010c]) of adding the overall highest hourly background NO_2 concentration to the model results was not reasonable to apply to the HECA Project. Thus, the additional refinement to the "first tier" approach that HECA has employed is temporal pairing of modeled and monitored values on an hourly basis. Justification for this refinement technique was provided in the January 2011 protocol, and its use was approved by both USEPA Region IX and OAQPS on March 11, 2011.

The approved method of combining the hourly NO_2 monitoring data with the hourly NO_2 impacts predicted from the modeling to show the maximum potential regional NO_2 impacts was employed in this analysis. Temporally pairing monitoring values with meteorological conditions is consistent with language in Appendix W, where monitored background concentrations are used to reflect contribution of regional levels of pollution not explicitly accounted for in the modeled inventory (USEPA, 2011).

The use of 5 years of hourly data will account for fluctuations in the background NO_2 concentrations. The model was run with sources operating at peak emissions, thus ensuring maximum impacts are predicted for every hour. These impacts are combined with the hourly background concentrations; thus when the background concentrations are high, the model predicted concentrations are also high, as modeled impacts are always maximized. Using the hourly temporal pairing technique of combining the modeled and background monitoring concentrations, the HECA regional modeling determines whether the "NO_X emissions increase from the proposed source will have a significant impact at the *point and time* of any violation" (USEPA, 2010c).

An exceptionally inclusive modeling emission inventory clearly represents the majority of emissions that could potentially contribute to the regional impact assessment, and the monitoring concentrations are intended to represent the contribution from minor sources and transportation sources not represented in the modeling inventory (USEPA, 2011). The use of temporal pairing of monitored background concentrations with modeled predicted concentrations on an hourly basis does not under-predict impacts because of numerous conservative assumptions used in the modeling analysis. All conservative assumptions employed in this modeling analysis are outlined in Section 6 of this modeling analysis.

3. BACKGROUND AIR QUALITY AND METEOROLOGICAL DATA

In preparation of demonstrating to show HECA Project operations compliance with the new 1-hour NO_2 NAAQS through modeling, a representative monitoring station with both hourly NO_2 and O_3 ambient monitoring data was chosen, an ambient NO_2/NO_X ratio was calculated, and meteorological data sets were obtained. The following sections provide further detail on those efforts. Additionally, based on information contained in the March 2011 USEPA Memo, the SJVAPCD was contacted and confirmed that the ambient air quality monitoring observation times are based upon the hour-beginning convention, and the meteorological monitoring observations recorded in the files obtained from their website are based upon the hour-ending convention. SJVAPCD prepared and provided the monitoring data to match the meteorological data time stamp format.

3.1 SELECTION OF A REPRESENTATIVE AMBIENT MONITORING STATION

Selection of a representative monitoring station was an important process because hourly O_3 data are used in conjunction with the PVMRM algorithm in AERMOD, and hourly NO_2 data would be used to represent ambient background NO_2 concentrations. The hourly NO_2 data were combined with the hourly NO_2 modeled impacts to estimate regional NO_2 impacts.

Several monitoring stations in Kern County, part of the San Joaquin Valley Air Basin, were considered for the NO_2 and O_3 data; these are shown in Figure 1 and Figures 3 through 5. The monitoring station nearest to the proposed Project Site that measured both pollutants from 2006-2010 is in Shafter, California. Data were processed and provided by the SJVAPCD. The data demonstrated completeness requirements during all quarters (more than 75 percent data capture) for all 5 years, per 40 Code of Federal Regulations Parts 50 and 58, February 9, 2010, Appendix S, 3.2(b) (USEPA, 2010a). The NO_2 and O_3 monitoring data cover the same years as the meteorological data used in the modeling; because both NO_2 and O_3 were obtained from the same monitoring station, they provide a better representation of the chemistry and balance between ambient NO_2 and O_3 concentrations.

The Shafter monitoring station is most representative of the rural location at the HECA Project Site. The Shafter monitoring station is on the roof of the local Department of Motor Vehicles building, which is surrounded by parking lots and near several roadways and a railroad, seen in Figure 3. California State Route 43 is 540 feet to the west of the Shafter monitoring station, and currently has an average daily traffic (ADT) volume of 14,000 trips (Caltrans, 2010). The Shafter monitoring station is 350 feet to the west of the Burlington Northern Santa Fe railroad. Due to the close proximity to State Route 43 and the railroad, the data from this station account for potential impacts from sources related to transportation. Since the HECA Project location is several miles from any major roadway, the Shafter monitoring station is expected to measure significantly more pollution from mobile sources than if a monitor were located next to the completed HECA Project. The ADT volumes at the HECA Project Site for the current year and future year (2017, with and without the Project), for both Alternative 1 (rail transportation) and Alternative 2 (truck transportation) are given in Table 1. The traffic volume near the Shafter monitoring station is currently more than 20 times larger than the volume near the Project Site. In future year 2017, with Project operations, the Shafter monitoring station will have approximately nine times the traffic volume than the traffic volume near the Project Site. Therefore, it is very conservative to represent the background pollution from transportation sources near the HECA Project Site with Shafter monitoring station data, although the Shafter data will represent the transportation emissions in the region appropriately.

The NO_2 and O_3 data used in the regional NO_2 analysis should adequately account for mobile emission sources; thus, the monitoring station chosen is located near mobile sources. Because the 1-hour NO_2 analysis that is being conducted is a regional analysis, it would be inappropriate to use O_3 data from a station heavily influenced by local sources.

Table 1
HECA Project Site Average Daily Traffic Counts

Road Segment	Existing (2012) ADT	2017 ADT without Project Trips	2017 ADT with Project Trips (Alternative 1)	2017 ADT with Project Trips (Alternative 2)
Adohr Road between Dairy and Tupman	273	301	775	787
Tupman Road between Adohr Road and Station Road	128	141	357	357
Dairy Road between Adohr Road and Stockdale Highway	188	206	464	476
Total ADT around Project Site	589	648	1,596	1,620

Source: Caltrans, 2010; HECA, 2012

The monitoring station is not near large industrial sources, but such sources will be accounted for in the regional modeling. Figures 6 and 7 graphically present the hourly and annual emissions (respectively) of stationary sources within 10 kilometers of the Shafter monitoring station. As can be seen, the stationary sources within the city limits are primarily smaller sources. Eight of the 10 sources within 2 kilometers of the Shafter monitoring station are owned and operated by the City of Shafter, and are electrical generators or pumps powered by emergency standby IC engines. The remaining two sources consist of an emergency standby IC engine and a small natural gas-fired heater, both under different ownership. On Figure 6, the larger hourly contributors (i.e., those with hourly emissions estimated at greater than 10 pounds per hour), beginning due west of the monitor and rotating counter-clockwise around the monitoring station are the following: Oasis Holstein Dairy; Vermeer Goedhart Dairy; North of River Sanitary District; Plains LPG Services, L.P.; and Performance Food Group. Comparison of the respective hourly and annual emissions for these facilities implies that the only equipment that operates on a regular (or non-emergency) basis is the equipment at Plains LPG Services, L.P., and, to a lesser extent, Oasis Holstein Dairy. The equipment at the remaining facilities consists largely of smaller sources or sources that do not operate on a regular basis (e.g., standby emergency ICengines). It is important to note that neither the smaller sources (i.e., those with NO_X emissions lower than 48 pounds/day) that are less frequently operated nor sources close to the monitoring station (as presented in Figures 6 and 7) will be included in the PSD modeling performed to assess compliance with the 1-hour NO_2 standard.

A description of the nearby sources included in the NO_2 analysis is provided in Section 4.2, presented in Figure 8, and a listing of the sources included in the modeling analysis is provided in Attachment A of this document.

Examination of the Shafter monitoring station 2006-2010 NO_2 hourly data provided by SJVAPCD showed that the 98th percentile daily maximum 1-hour concentration averaged over the 5 years was 62 ppb, which is below the standard. There were very few hours when the measured background concentration is near or above 100 ppb.

Because the Shafter monitoring station is near mobile sources but no large industrial sources, and is not downwind from an urban area, the data appropriately represent ambient NO_2 and O_3

concentrations expected to be found throughout the rural San Joaquin Valley. Therefore, the Shafter monitoring station was chosen to represent the background NO_2 and O_3 data in the modeling.

Other monitoring stations that were considered for NO_2 and O_3 data are shown in Table 2. These other stations did not meet the following criteria:

1. Meet data completeness requirements;
2. Match the rural land use surface parameters of the proposed Project Site;
3. Show close proximity to the Project Site compared to other monitoring stations; or
4. Monitor NO_2 or O_3 data.

Table 2
Monitoring Stations Considered for Ozone and Nitrogen Dioxide Data, Kern County, San Joaquin Valley Air Basin

Monitoring Station	NO_2 Data Availability Years	O_3 Data Availability Years	Distance from Project Site (Miles)	All Quarters Between 2006-20010 Have 75% Raw Data Capture for NO_2 and O_3?[1]
Shafter-Walker Street	1989-2010	1989-2010	13	Yes
Taft College	Not Available	Not Available	13	Not Applicable
Bakersfield-5558 California Avenue	1994-2010	1994-2010	18	Yes
Maricopa-Stanislaus Street	Not Available	1987-2010	19	Not Applicable
Bakersfield-Golden State Highway	1994-2008	1994-2009	21	No; Station has been shut down. Ozone sampling ended in 2009, and NO_2 sampling ended in early 2010.
Bakersfield-410 E Planz Road	Not Available	Not Available	21	Not Applicable
Oildale - 3311 Manor Street	Not Available	1980 - 2010	28	Not Applicable
Arvin - Bear Mountain Blvd	1989-2008	Not Available	34	Not Applicable
Arvin- Di Giorgio	Not Available	2009 - 2010	39	Not Applicable

Notes:
[1] Raw data per quarter must meet 75 percent data capture, per 40 Code of Federal Regulations Parts 50 and 58, February 9, 2010, Appendix S, 3.2(b).
Data from CARB (2010): http://www.arb.ca.gov/aqmis2/aqdselect.php?tab=specialrpt.

Bakersfield NO_2 and O_3 data were not used. The Bakersfield Golden State Highway station did not meet data completeness requirements. The Bakersfield California Avenue station's suburban location is not representative of the rural HECA Project Site. Figure 1 displays an overview image of the HECA Project Site and locations of several nearby monitoring stations. Close-up aerial images of the HECA Project Site next to the surface meteorological station used in the AERMET files are shown in Figure 2. Finally, zoomed-in locations of the monitoring stations at Shafter, Bakersfield-California Avenue, and Bakersfield-Golden State Highway are presented in Figures 3 through 5, respectively.

3.1.1 Handling of Missing Hourly O_3 & NO_2 Data for Shafter Monitoring Station

To run PVMRM in AERMOD, hourly O_3 data are required. These data cannot have any missing values for the model to function correctly, thus missing data must be filled appropriately. Likewise, NO_2 background data added to modeled NO_2 concentrations must be complete. SJVAPCD used the following convention to fill in missing hours in the raw hourly Shafter NO_2 and O_3 background data.

The maximum raw monitoring value for each hour in each month of the 5 years was obtained. Missing hours were filled with the maximum value that occurred for that hour in that month for all years. This method of handling missing data will not underestimate the missing background O_3 or NO_2 concentrations because the maximum concentration for the given hour was substituted.

3.2 AMBIENT NO_2/NO_X RATIO

The PVMRM algorithm uses the ambient or equilibrium NO_2/NO_X ratio in calculating the predicted NO_2 concentrations. On an hourly basis, the ambient NO_2/NO_X ratio will vary depending on nearby sources, meteorological conditions, and ambient O_3 concentrations. The PVMRM algorithm in AERMOD is not designed to accept hourly ambient NO_2/NO_X ratios; therefore, a regional annual ratio was used in the model.

The highest seasonal average NO_2/NO_X equilibrium ratio from the Shafter NO_2 monitoring station based on hourly data for 2006 through 2010 was 0.83, occurring in the summer (CARB, 2012). However, the modeling analysis presented in this report used a NO_2/NO_X equilibrium ratio of 0.9, which represents the hourly upper bound, as recommended by USEPA Region IX. With this point considered, the use of the default NO_2/NO_X equilibrium ratio of 0.9 in PVMRM is another conservative assumption in the HECA NO_2 modeling analyses, as it will allow more conversion of NO_X to NO_2 than has been observed in ambient data.

3.3 METEOROLOGICAL DATA

Hourly surface data were obtained from the SJVAPCD for the Bakersfield Meadows Field Airport (BFL) meteorological station for the years 2006 through 2010. When using off-site meteorological data, USEPA requires 5 years of the most recent and representative data available. The SJVAPCD hourly surface observation data included meteorological parameters of temperature, dew point, pressure, wind speed, wind direction, cloud cover, and ceiling height. SJVAPCD has prepared a document describing their meteorological processing methodology, "Procedures for Downloading and Processing NCDC Meteorological Data" (SJVAPCD, 2010a), provided in Attachment B.

The BFL station is approximately 20 miles northeast of the HECA Project, as shown in Figure 1. The data meet the USEPA criteria for representativeness, and are suitable based on proximity and terrain similarities between the Project Site and BFL. The terrain immediately surrounding the meteorological station and the HECA Project is rural, as shown in the aerial photographs of Figure 2. Circles with a 1-kilometer radius around the HECA Project Site and the meteorological station show similar terrain, including open fields and semi-developed land use categories. Projected HECA Project structures will create a more developed site at the Project

location, producing some developed land use similar to the airport. There are no major geographical features that could influence the meteorological conditions between or near the locations.

The BFL station and the HECA Project Site both lie within the southern portion of the San Joaquin Valley, between the foothills of the Sierra Nevada Mountains to the east, the Diablo Mountain Range to the west, and the Tehachapi mountains to the south. The HECA Project Site will sit at 288 feet above sea level, while the BFL station sits at 489 feet. The climate in the valley is warm and semi-arid, with the wet season occurring between October and April. The Bakersfield 30-year average for normal sky coverage is 189 days of clear skies per year, 80 days of partly cloudy skies, and 92 days of cloudy skies. Summers are clear and dry. The relative humidity is low in the summer and high in the winter, with an average annual relative humidity of 54 percent. Winds in the San Joaquin Valley often flow with the axis of the valley, and thus blow frequently from the northwest. During the summer the northwest sea breezes frequent the Bakersfield area, especially during hot summer periods, which may carry dust and bring thermal instability. As air descends downward over the mountain ranges, it warms and dries out, allowing temperatures in the city and adjacent areas of the southeastern San Joaquin Valley to run warmer than areas farther north. A very strong eastern Chinook wind will often blow through the Tehachapi Pass during the winter months. Frontal passages are also common in winter months throughout the valley (NCDC, 2010; NOAA, 2008).

An annual wind rose based on the 5 years of Bakersfield surface data was provided in Appendix E-1, Seasonal and Annual Wind Roses, of the AFC Amendment (2012). Winds blow predominantly from the northwest, with an average annual speed of 6.5 miles per hour, but winds are often calm. Western Regional Climate Center Bakersfield Meadows Airport temperature data for the years 1940 through 2012 indicate the average annual high and low temperature for this station are 78 degrees Fahrenheit (°F) and 49°F, respectively (WRCC, 2012).

Only two long-term upper air stations exist for the entire state of California that collect enough data for use in air quality modeling. These stations are in Oakland and San Diego. There is an upper air station at Vandenberg Air Force Base in California, but this station has insufficient hourly data for modeling. SJVAPCD chose the Oakland International Airport upper air station for all meteorological data processing. Data were obtained from the National Oceanic and Atmospheric Administration Radiosonde Database for the same years as the surface station data (NOAA, 2010). The Oakland Airport upper air station is approximately 235 miles northwest of the Project Site. Using the Oakland upper air data and the Bakersfield surface data, AERMET creates an hourly vertical wind profile to estimate wind parameters at different plume heights (USEPA, 2004).

The USEPA AERMOD Implementation Guide (USEPA, 2008a) discussed a fairly new tool called AERSURFACE, which may be used to establish realistic and reproducible surface characteristic values around the meteorological surface station (USEPA, 2008b). SJVAPCD used the AERSURFACE program to determine surface characteristics for input into the AERMET processor program for the Bakersfield meteorological data set. AERSURFACE uses USGS National Land Cover Data 1992 archives to determine the Albedo, Bowen ratio, and surface roughness length representative of the surface meteorological station.

For the AERSURFACE input, the USEPA-recommended surface parameter distance of 1 kilometer was used to develop surface roughness values, and a 10-kilometer radius was used for Albedo and Bowen ratios. Figure 2 displays an aerial view of the HECA Project Site and BFL meteorological station site, with a circle 1 kilometer in radius surrounding both locations. The meteorological station is at an airport, does not receive continuous snow cover in the winter, and is not in an arid region. The Bowen ratio calculation is based on comparison of precipitation during the study period to a 30-year climate average. If conditions are within the upper 30th percentile moisture conditions, it is considered wet conditions; the lower 30th percentile represents dry conditions, and the middle 40th percentile represents average conditions.

The HECA Project Site is in close proximity to the BFL meteorological station, so the locations have a similar climate, the land use surrounding each location is comparable, and there are no major geographical features between the HECA site and weather station that could cause a difference between the meteorological conditions at the two locations. Therefore, the meteorological data used in the NO_2 regional modeling analysis from the BFL station are representative.

4. EMISSIONS SOURCES

4.1 HECA PROJECT

The emission scenario used in the NO_2 1-hour SIL and NAAQS cumulative modeling was developed following guidance from the March 2011 USEPA Memo. To minimize emissions, all HECA emissions sources will use best available control technology (BACT).

For this modeling, the CTG/HRSG and coal dryer operate in normal on-peak (Case 1) power mode. Start-up emissions for the CTG/HRSG are limited to 105 hours per year, while shut-down emissions are limited to 18 hours per year. Start-up emissions for the coal dryer are limited to 104 hours per year, with shut-down emissions at 8 hours per year. Annualized maximum 1-hour NO_2 start-up/shut-down emission rates for these two sources are lower than their normal maximum NO_2 1-hour rates; therefore, the maximum normal NO_2 1-hour emission rates for the CTG/HRSG and coal dryer were used.

Similarly, the SRU flare and tail gas thermal oxidizer have maximum impacts during normal operations with pilot and process vent disposal, respectively, rather than during an annualized start-up period. The Rectisol® and gasification flares were included with maximum annualized start-up flaring emission rates, which are higher than their normal emission rate during pilot mode.

The auxiliary boiler and nitric acid unit operations were included at their peak hourly emission rate. The ammonia plant start-up heater also was included with an annualized start-up 1-hour NO_2 emission rate. Finally, all three ancillary diesel engines, including the two emergency diesel generators and firewater pump, were included in the modeling with annualized emission rates. Mobile sources were not included in this modeling scenario.

The emission rates and stack parameters used in these analyses for the HECA sources can be found in Table 3.

Table 3
HECA Source Emission Rates and Stack Parameters
Used in the NO_2 SIL and NAAQS Analyses

Source	Operating Condition Associated with Emission Rate	Stack Height (ft)	Temperature (°F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	NO_2 emissions (lb/hr)
HRSG Stack	Normal On-Peak Emissions (Case 1)	213.00	200.00	53.81	23.00	25.01
Coal Dryer	Normal On-Peak Emissions (Case 1)	305.00	200.00	19.16	16.00	4.37
Tail Gas Thermal Oxidizer Stack	Normal operations	165.00	1200.00	50.93	2.50	3.12
Auxiliary Boiler	Normal operations	80.00	300.00	30.18	4.50	1.28
Rectisol® Flare	Annualized emissions, start-up flaring	217.83	1831.73	65.62	0.87	0.24
Gasification Flare	Annualized emissions, start-up and shut-down flaring	219.63	1831.73	65.62	1.22	0.66
SRU Flare	Normal Operations, Pilot	215.00	1831.73	65.62	0.32	0.04
Nitric Acid Plant Stack	Normal operations	145.00	239.00	17.11	8.00	4.18
Emergency Diesel Generator 1	Annualized emissions	20.00	760.00	221.05	1.20	0.02
Emergency Diesel Generator 2	Annualized emissions	20.00	760.00	221.05	1.20	0.02
Emergency Diesel Firewater Pump	Annualized emissions	20.00	850.00	155.91	0.70	0.02
Ammonia Synthesis Plant Start-up Heater	Annualized emissions	80.00	300.00	18.71	3.50	0.01

Notes:
ft = foot/feet
Lb = pound
Hr = hour
HRSG = heat recovery steam generator
NAAQS = National Ambient Air Quality Standard
NO_2 = nitrogen dioxide
sec = second
SIL = Significant Impact Level
SRU = sulfur recovery unit

4.1.1 NO_2/NO_X In-Stack Ratios for HECA Sources

In stack NO_2/NO_X ratios were determined for all sources in the NO_2 modeling for use in the ozone limiting method PVMRM. For the emergency generators, firewater pump, ammonia start-up heater, and auxiliary boiler, the NO_2/NO_X in-stack ratios were obtained from the SJVAPCD 2010 draft guidance document, *Assessment of Non-Regulatory Options in AERMOD Specifically OLM and PVMRM* and the CAPCOA *Modeling Compliance of the Federal 1-hour NO_2 NAAQS*

(Attachment C). For the emergency generators and fire water pump, an in-stack ratio of 0.2 was used from the "IC Engines (Diesel)" category. The ammonia start-up heater used an in-stack ratio of 0.32 from the "Heaters (NG)" category. For the auxiliary boiler, an in-stack ratio of 0.1 was used from the "Boilers (NG)" category.

Limited information is available regarding in-stack NO_2/NO_X ratios for thermal oxidizers and flares. The exhaust from the thermal oxidizer or flares will have very little to no residence time in the stack, so almost no conversion of nitrogen oxide (NO) to NO_2 is expected. For these sources, it was conservatively assumed that 10 percent of the NO_X will be NO_2.

No data exist for the NO_2/NO_X in-stack ratio for turbines burning hydrogen-rich fuel or the associated coal dryer. The turbine vendor expects the NO_2/NO_X in-stack ratio will be similar to turbines that burn natural gas. Based on the in-stack NO_2/NO_X ratio of 0.091 for a natural gas turbine as determined by SJVAPCD guidance, and accounting for the conversion of NO to NO_2 across the oxidation catalyst that could be as high as 20 percent (NO_2/NO_X ratio 0.2), HECA proposes to use the conservative NO_2/NO_X in-stack ratio of 0.3 for all turbine and coal dryer operating conditions. Neither the turbine nor oxidation catalyst vendor could provide written documentation regarding the NO_2/NO_X in-stack ratio, although this ratio was their professional engineering estimate.

Emissions from the nitric acid plant will be cleaned before being discharged to the atmosphere by catalytic decomposition and reduction of both nitrous oxide (N_2O) and NO_X. The N_2O emissions are treated in a tertiary reduction system, in a reducing catalyst that uses high temperature rather than a reducing agent, to convert 95 percent of the remaining N_2O emission to molecular nitrogen (N_2) and nitric oxide (NO). The NO_X emissions (including the NO formed in the N_2O converter) are then reduced in one or more selective catalytic reduction (SCR) units, with injected ammonia as a reducing agent, as is typical for NO_X control in flue gas systems. The nitric acid unit vendor and Project design engineers estimate that approximately 50 percent of the NO converts to NO_2 in the exhaust, therefore an in-stack ratio of 0.5 was used.

4.2 NEARBY SOURCES

Section 8.2 of Appendix W of 40 CFR, Part 51 (the USEPA's *Revision to the Guideline on Air Quality Models* [USEPA, 2005]) refers to background concentrations as "an essential part of the total air quality concentration to be considered in determining source impacts." When a source is not isolated, a multi-source model (i.e., AERMOD) is prescribed to establish the potential impact of nearby sources. In the recommendations subsections for multi-source areas, the following key points are made:

- Contributions from ***nearby sources*** and contributions from ***other sources*** should be determined.

- ***Nearby sources*** are those expected to cause a significant concentration gradient in the vicinity of the source or sources under consideration; the number of such sources is "expected to be small," given the complexities of modeling specific projects (i.e., unique modeling situations, large numbers of variables). It specifically states that the definition is provided merely as guidance and is not intended to alter professional judgment.

- An appropriate model should be employed along with emission input data as shown in Table 8-1 or 8-2 of the USEPA guidelines (USEPA, 2005); any unpermitted sources should be modeled at their maximum physical capacity to emit.

- Only sources that would run simultaneously with the primary source being modeled (i.e., HECA) are to be modeled. As an example: "emergency backup generators that never operate simultaneously with the sources that they back up would not be modeled as nearby sources."

- Interactions between the primary source and the various nearby sources should be evaluated by examining the areas of maximum impact for each separately, followed by examination of the area of maximum impact where the two are combined, on a "trial and error" basis.

- ***Other sources*** are defined as the "portion of the background attributable to all other sources (e.g., natural sources, minor sources, and distant major sources)" to be determined using prescribed methods.

Other sources that were not accounted for in the background data, such as minor sources and distant major sources, were included in the modeling analysis. For simplicity in discussion, other sources and nearby sources are collectively referred to as "nearby sources."

4.2.1 Nearby Source Screening and Selection Process

URS requested information on NO_2 emissions sources surrounding the HECA Project Site from the SJVAPCD for the PSD analysis. SJVAPCD provided a list of over 8,500 permitted sources to a distance of approximately 75 kilometers from the center of the HECA Project Site. Upon closer inspection, the NO_X emissions data for approximately 75 percent of these sources contained either no values for the daily or annual emission rates or presented values of zero. For the most part, the zero emissions sources consisted of processes or equipment that would not emit NO_X (e.g., VOC sources, such as gasoline stations, storage tank operations, etc., or particulate matter [PM] sources, such as wood processing, dust control equipment, etc.). The zero emissions sources were further screened for dormant NO_X equipment that was flagged as such in the SJVAPCD's equipment description (i.e., dormant equipment typically contained the word "DORMANT" in the SJVAPCD's equipment description). This was also done by searching the zero emissions equipment description for the terms "ENGINE" and/or "TURBINE." Any engines and/or turbines with zero emissions were labeled as "assumed dormant."

Furthermore, equipment was analyzed based upon its distance from the HECA Project Site. The fairly large distance between the HECA Project Site centroid and its property fence line (approximately 1.3 miles) resulted in URS extending the radii (or distance) to screen. The following distances were used to evaluate the sources surrounding the HECA Project Site:

- Source distance less than 11.4 miles (18.3 kilometers)

- Source distance greater than or equal to 11.4 miles (18.3 kilometers), and less than or equal to 32.4 miles (52.1 kilometers)
- Source distance greater than 32.4 miles (52.1 kilometers)

After omitting sources for which NO_X emissions were either zero or not provided, URS used a qualitative approach to further refine the sources used in this modeling analysis. This approach was based upon professional judgment and made use of various source metrics or a combination thereof, including, but not limited to the following:

- size (e.g., horsepower [hp], heat input rating, or emissions)
- type of source
- frequency of use (e.g., emergency/standby internal combustion (IC) engine/ emergency fire pump, test operation)
- relative emission rate (Q) divided by source distance from HECA centroid (d), Q/d

and, specifically for IC engines:

- USEPA Tier emission rating
- Emergency or non-emergency IC engine

The use of Q/d was prescribed as a viable screening method for PSD projects in a 1985 letter by the State of North Carolina Department of Natural Resources and Community Development (NCDNRCD) (NCDNRCD, 1985). That particular reference suggested that this simple screening method could be employed to:

> "rapidly and objectively eliminate from the emissions inventory those sources that are beyond the PSD impact area yet within the screening area, but are not likely to have significant interaction with the PSD source."

Two Q/d values labeled Q/D-1 and Q/D-2, with units of tons per year per kilometer (ton/yr/km), were calculated for each source by dividing the respective daily and annual emissions values by its distance from HECA. As expected, the values calculated using daily emissions are more conservative (except in the case of several flagged sources [errant data]); that is, they would cause more sources to be included in the analysis.

A summary of the number of nearby sources included in the modeling analyses that exceed a Q/d threshold of 2, one order of magnitude less than the threshold of 20 used in the NCDNRCD document (NCDNRCD, 1985), is provided in Table 4.

Using professional judgment, a number of facilities (especially oil production/refining operations, cogeneration plants, etc.) were included based upon the fact that they had a significant number of sources or yielded significant emissions, even if they had Q/d values less than the screening threshold presented in Table 4.

As a conservative check on information presented in Table 4, additional effort was made to evaluate a "totalized" facility Q/d, whereby the sum of the Q/d values for a facility's sources

Table 4
Summary of Number of Sources with a Q/D Threshold of 2

Distance	Threshold Value	No. of Sources Included, Using ONLY Q/d Calc	
		Q/D-1 ([ton/yr]/km) (based on daily emissions)	Q/D-2 ([ton/yr]/km) (based on annual emissions)
< 11.4 mi (18.3 km)	2	33	22
≥ 11.4 mi (18.3 km) and ≤ 32.4 mi (52.1 km)	2	90	39
> 32.4 mi (52.1 km)	2	3	0

Notes:
< = less than
> = greater than
≤ = less than or equal to
≥ = greater than or equal to
mi = mile
km = kilometer
[ton/yr]/km = tons per year per kilometer

(those sources with NO_X emission rates greater than 2 pounds per hour [or 48 pounds per day]) was compared to the Q/d threshold of 2 used above. No such cases were found; therefore, no additional facilities were included based upon totalized facility emissions.

Smaller co-located sources within the lesser 10-mile radius were also more likely to be included than those at greater distances.

The result of adding the various co-located sources, the sources found at fairly large facilities (even those below threshold values), removal of intermittent sources, plus all the other factors resulted in the modeled source count presented in Table 5.

Table 5
Sources Included in the 1-hour NO_2 PSD Analysis

Distance Range	Total
< 11.4 mi (18.3 km)	108
≥ 11.4 mi (18.3 km) and ≤ 32.4 mi (52.1 km)	257
> 32.4 mi (52.1 km)	6
Total	371

Notes:
< = less than
> = greater than
≤ = less than or equal to
≥ = greater than or equal to
mi = mile
km = kilometer
NO2 = nitrogen dioxide
PSD = Prevention of Significant Deterioration

The source counts above are based upon professional judgment, while also taking into account the sources with a Q/D-1 or Q/D-2 greater than or equal to 2; in addition, small sources that could not have a significant impact were removed. Small sources (co-located or not) with a daily emission rate less than or equal to 48 pounds per day (equates to 2 pounds per hour) were omitted from the source list due to their limited size. Emergency/standby engines at nearby facilities were not included based on the March 2011 USEPA Memo modeling guidance. However, 78 IC engines powering compressors, 13 IC engines for agricultural pumping, and 3 IC engines used to start gas turbines were included for the regional modeling analysis.

The number of sources discussed above may differ from that discussed in the January 2011 modeling protocol; such reasons for removing sources may include, but are not limited to, the following:

1. duplicative/backup sources;
2. additional information provided for a given source;
3. omitting emergency engines at nearby facilities from the modeling inventory; and
4. if a source closer to HECA does not result in a significant concentration gradient, a similar source farther from HECA may be eliminated.

Several source data handling assumptions were used as follows:

- Multiple Flares: If SJVAPCD information showed that a facility has more than one (1) flare or emergency flare in its permitted inventory, then at least one of any duplicate flares (i.e., flares of equivalent heat input capacity that result in equivalent pseudo-stack parameters, as discussed later) or the most conservative flare was used; professional judgment was used to estimate the conservativeness of stack parameters in combination with the emission rates provided by the SJVAPCD;
- Sources immediately adjacent to the Shafter monitoring station that are already included in the background data were excluded from the analysis.

All nearby sources included in the NO_2 analysis were modeled using their maximum hourly emission rate. The maximum hourly emission rates were estimated by dividing each source's maximum permitted daily emissions (as provided by SJVAPCD) by 24 hours. The modeling analysis includes all nearby sources operating simultaneously with maximum emissions; this is an extremely conservative assumption and is guaranteed to overestimate potential impacts from these sources during actual HECA Project operations. The SJVAPCD provided nearby source list of over 8,000 sources, which is presented electronically with the modeling files. The list of the modeled nearby sources with stack parameters is provided in Attachment A.

Figure 8 presents the hourly emissions from nearby sources included in the modeling analysis. Sources located at the same facility have been combined in order to simplify the plot. The largest facilities within 10 kilometers of the HECA Project are OEHI (IC engines and heaters) and Elk Hills Power (turbine). The largest contributors (greater than 100 pounds per hour) are several cogeneration plants (Sycamore Cogeneration Co. and Kern River Cogeneration Co.) and oil and gas facilities (Aera Energy, LLC and Chevron, USA Inc.) located greater than

30 kilometers from the HECA Project Site. A complete list of all sources is included as Attachment A and in the modeling files presented electronically with this submittal.

4.2.2 Nearby Source Emissions and Stack Parameters

The emissions for the nearby sources included in the modeling analysis are tabulated in Attachment A. A collective sum of approximately 1.5 tons of NO_2 per hour is assumed to be emitted by all nearby sources, running continuously with the modeled HECA emissions.

Stack parameters for the nearby sources included in the analysis were either provided by SJVAPCD or derived from similar equipment based on professional judgment. URS filed a Public Records Request with the SJVAPCD in early-November 2009 for permit-related information from 25 facilities within approximately 10 miles of the HECA Project Site. The request included the following document types: permit applications, emissions inventory statements, AB2588 "Hot Spots" Information, engineering evaluations, and determinations of compliance. Furthermore, the request called for documents that included a summary of modeling files, including information on stack parameters and source coordinates. In late November 2009, URS received two DVDs of information for the 25 facilities. A very large number of PDF files were provided on the disks for each facility; however, review of each PDF file proved overwhelming and instead only the larger files were perused for useful information. The most useful information was typically a source test, air toxics inventory, or engineering evaluation; however, few such documents were found. As stack parameter information was found for particular sources, such information was applied to other sources based upon their similarity in size and/or orientation.

If adequate source information was not provided to approximate source parameters (e.g., a flare without a heat input rating), parameters for a similar source with a similar emission rate at the same facility or similar facility were used. Similarly, if stack parameters could not be readily found in information provided by the SJVAPCD via a literature search or via internet searches, then reasonable stack parameters for similar equipment were used, or approximate values were used based upon the professional judgment of a URS technical staff member.

Pertinent source information provided by the SJVAPCD included locations (as UTM coordinates), emission rates, equipment descriptions, facility number, permitted source number, etc. Due to the size of the modeled area and number of sources, the accuracy of facility locations provided by the SJVAPCD was not questioned, nor investigated.

In parallel with the request for information from SJVAPCD, Occidental of Elk Hills, Inc. (OEHI) was approached independently. OEHI is located fairly close to the HECA project and consists of a very large number of sources. The following information received for approximately two-thirds of the sources at OEHI proved useful in the modeling analysis:

- source coordinates
- stack temperature
- stack height
- stack diameter
- base elevation

- exhaust stack temperature
- equipment status (active/dormant/emergency)
- equipment make, model and permit number

Coordinates for the remaining one-third of OEHI sources were estimated; stack parameters for those same sources (and stack flow rates or velocities for the above two-thirds) were estimated based upon professional judgment and/or research of parameters for similar equipment.

One type of regional NO_X source found in great numbers and densities in oil field applications was a gas- and/or vapor-fired steam generator (most common size was 62.5 MMBtu/hr). Source parameters for these steam generators, including stack height, stack diameter, exhaust stack temperature, and a stack flow rate and/or velocity, were found in a Human Health Risk Assessment (HRA) produced by the SJVAPCD for a document entitled "Notice of Preliminary Decision - ATC/Cert of Conformity," addressed to Chevron USA and dated 12-8-10. The HRA was dated 10-29-10 and addressed 62.5 MMBtu/hr steam generators specifically.

In general, SJVAPCD-provided UTM coordinates were identical for all sources at a given facility (with the same facility ID). This resulted in a considerable amount of co-located sources being input to the modeling. In some instances, all of which are noted appropriately, the SJVAPCD-provided coordinates were adjusted using aerial imaging software, the facility footprint (where appropriate), and professional judgment to distribute sources across a larger area. Such was the case for several apparent oil fields (e.g., Aera Energy LLC [Facility ID No. 1135]; Chevron USA, Inc. [Facility ID No. 1141]) that consisted of the steam generator equipment previously mentioned and/or combined cycle gas turbines equipment providing both electricity and steam. The coordinates of selected sources at OEHI [Facility ID Nos. 382, 2234]) were also adjusted where facility information was not provided; this facility included a wide variety of equipment.

Notes pertaining to the source of input information (e.g., emissions rates or stack parameters used) for all nearby sources included in modeling are tabulated in Attachment A.

4.2.2.1 Nearby Source NO_2/NO_X In-Stack Ratios

NO_2/NO_X in-stack ratios were obtained from the SJVAPCD 2010 draft guidance documents, *Assessment of Non-Regulatory Options in AERMOD Specifically OLM and PVMRM* and the updated Recommended In-Stack NO_2/NO_X Ratios (Attachment C), and Master List of NO_2/NO_X ratios from EPA Region 10, which is provided electronically with the modeling files in the submittal of the AFC Amendment (2012). Table 6 contains a listing of the NO_2/NO_X in-stack ratios used for the various combinations of nearby source types and fuels.

As seen in Table 6, the NO_2/NO_X in-stack ratio for the nearby sources was chosen by equipment and fuel type, as provided from SJVAPCD guidance, and USEPA Region 10 for large gas turbines. Where good information regarding a particular type of source was not available, a high ratio was used. In-stack ratios used for each nearby source are provided with the modeling source input parameters in Attachment A.

Table 6
NO_2 / NO_X In-stack Ratios Used in Modeling

Source Type	Fuel	In-stack Ratio Used
Boilers/Steam generators	biomass, NG, vapor	0.1
Turbines (including cogeneration, simple-/ combined-cycle, and gas compressor applications)	NG	0.1032 (small turbines) 0.17 (large turbines)
Emergency turbine	diesel	0.1
Other cogeneration sources	solid fuel, multi-fuel	0.1
Process heaters/dryers	NG, vapor	0.32 / 0.1 (heaters or both) / (dryers)
IC engines (including those acting as gas turbine starters or powering pumps)	diesel	0.2
	NG	0.1
IC engines (acting as compressors)	diesel	0.2
	NG	0.6
Ovens	NG	0.32

Notes:
NO_2 = nitrogen dioxide
NO_X = nitrogen oxide
NG = natural gas

5. MODELING RESULTS

Because NO_2 impacts from HECA sources exceeded the 1-hour SIL, a cumulative impact assessment was completed to determine whether the Project would cause or contribute to a modeled violation of the NAAQS. HECA sources were combined with nearby sources and modeled in AERMOD with PVMRM, and hourly NO_2 ambient background concentrations were added to the hourly model predictions. Section 5.1 presents the results from HECA sources alone compared with the 1-hour NO_2 SIL, and defines the area of impact receptors to be subsequently used in the regional analysis. Section 5.2 presents results from the regional analysis, which presents the HECA sources, nearby sources, and background modeled design value in comparison to the NAAQS.

5.1 RESULTS FOR SIL AND AREA OF IMPACT FROM HECA SOURCES

Screening modeling determined whether HECA operational impacts had the potential to cause or contribute to a violation of the NAAQS, comparing the modeled maximum first high concentration averaged over 5 years to the NO_2 1-hour Class II interim SIL of 4 ppb. Only permitted stationary sources were included in the modeling analyses.

The modeled NO_2 concentration from HECA was predicted to be 24 μg/m^3, compared with the interim NO_2 1-hour SIL of 7.55 μg/m^3 (4 ppb) for Class II areas. This NO_2 1-hour concentration is the maximum first high concentration averaged over 5 years. In this initial impact analysis, approximately 2,500 receptors exceeded the NO_2 1-hour SIL within 15 kilometers of the site, and were used as the HECA area of impact for the refined modeling analysis.

5.2 RESULTS FOR CUMULATIVE MODELING ANALYSIS

The MAXDCONT option in AERMOD was run to determine the NO_2 1-hour impact contribution from HECA. The option was run from rank 8 (or, the 98th percentile daily maximum value per receptor averaged over 5 years) to rank 20, with a threshold value equal to the NO_2 1-hour NAAQS (188 μg/m^3). The target source group was set to all sources (HECA, regional sources, and background). This setup option continues to examine the concentrations for all ranks until the impacts from all sources are less than the threshold value of 188 μg/m^3. This option was used to obtain any exceedances of the NAAQS from all sources and, if an exceedance occurs, whether or not HECA's contribution is greater than or equal to the SIL at that point in time and space. HECA stationary sources were modeled using the higher of their normal operating emission rate or an annualized intermittent operation emission rate.

The maximum modeled 5-year average 8th high (98th percentile) 1-hour daily concentration (design value) at any receptor was 126 μg/m^3, which complies with the 1-hour NO_2 NAAQS of 188 μg/m^3. The total predicted design value includes HECA sources, nearby regional sources and background measured concentrations of NO_2.

The regional modeling analysis showed that no concentrations were predicted to be greater than the NAAQS. Therefore, HECA does not cause or significantly contribute to a violation of the NO_2 1-hour NAAQS.

6. CONSERVATISM IN THE MODELING ANALYSIS

Following the USEPA modeling guidance documents resulted in the inclusion of many conservative assumptions within the modeling analysis. The conservative data assumptions used as input to the modeling analysis are outlined below:

1. Emissions from the nearby sources were input at maximum potential to emit out as far as 75 kilometers. For most sources the maximum permitted emission rates are significantly higher than their actual emission rates, and thus the modeling over-predicts the impacts from these sources.

2. Simultaneous operation of HECA sources and nearby sources, all with maximum hourly permitted emission rates, for all hours of the 5-year meteorological data set.

3. For NO_2/NO_X in-stack ratios, a high ratio was used where good information regarding a particular type of source was not available.

4. The hourly upper bound NO_2/NO_X equilibrium ratio of 0.9 was used, and this value is higher than the maximum seasonal hourly ratio of 0.83.

5. Hourly NO_2 background data from the Shafter monitoring station are used as a surrogate for emissions from transportation sources near the HECA Project, although they will also contain contributions from sources near the monitoring station.

6. The traffic volume near the Shafter monitoring station is expected to be approximately nine times larger than the traffic volume near the HECA when operation starts. The NO_2 data from the Shafter monitoring station represents significantly more vehicular emissions than are expected near HECA.

7. HECA has purchased Emission Reduction Credits (ERC) to cover the total HECA Project annual NO_X emissions at a 1.5-to-1 ratio. No credit has been taken for these emission reductions in the modeling analysis.

The use of so many conservative inputs into the model have the effect of removing accuracy from the analysis and analyzing a situation that could never be observed in reality, thereby grossly overestimating the potential impact from HECA Project operations and nearby sources.

7. CONCLUSION

The HECA Project is a revolutionary power and manufacturing facility and one of the first projects in USEPA Region IX that is faced with showing compliance with the new, statistically based 1-hour NO_2 NAAQS. Although USEPA has created guidance documents for conducting modeling to show compliance with the new standard, many aspects of conducting a regional analysis are still controversial between different permitting agencies. HECA has been in constant contact with USEPA Region IX and SJVAPCD, seeking additional modeling guidance in order to show compliance with the new 1-hour NO_2 NAAQS. This analysis was based on techniques agreed to with USEPA Region IX, OAQPS, and SJVAPCD.

The modeling results compiled and presented in the report clearly show that the HECA Project, combined with nearby sources to a distance of 75 kilometers, conservative ambient air quality background values, and a number of other of other conservative assumptions, would comply with the 1-hour NO_2 NAAQS.

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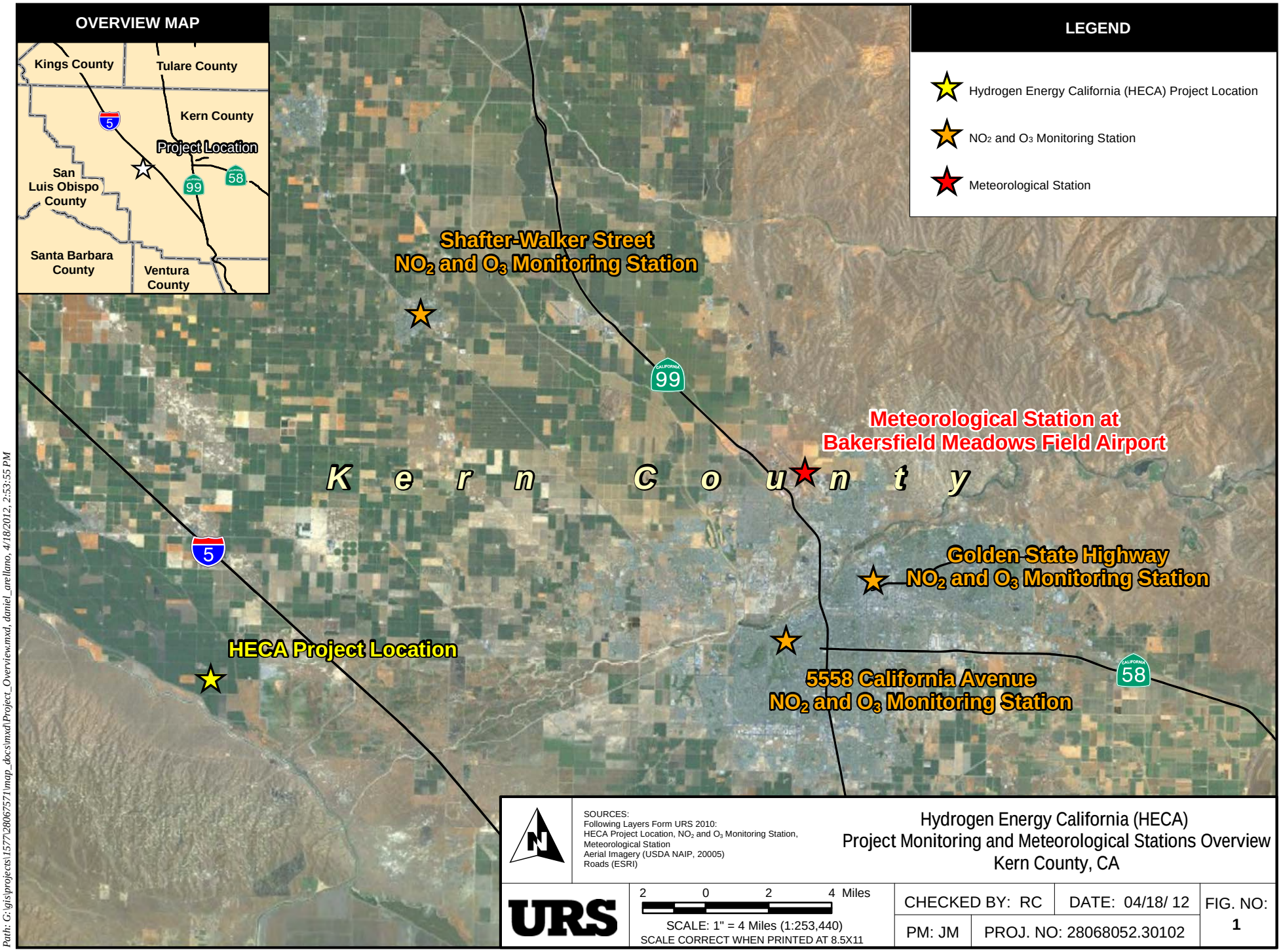

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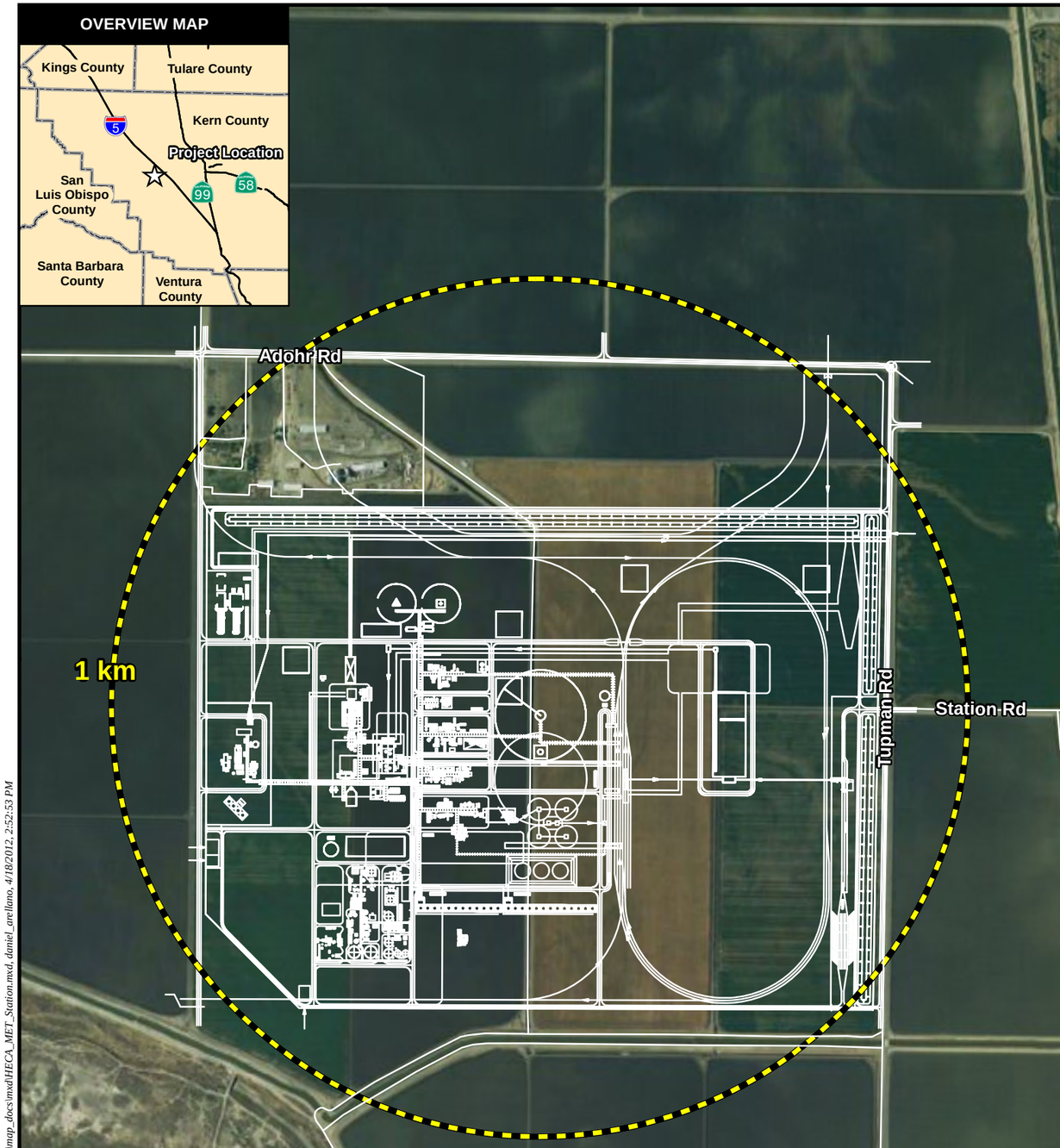

SOURCES:
HECA Location and Site Plan (URS 2010)
Aerial Imagery (USDA NAIP, 2005)
Roads (ESRI)

Hydrogen Energy California (HECA)
Project Location and Site Plan
Kern County, CA

URS

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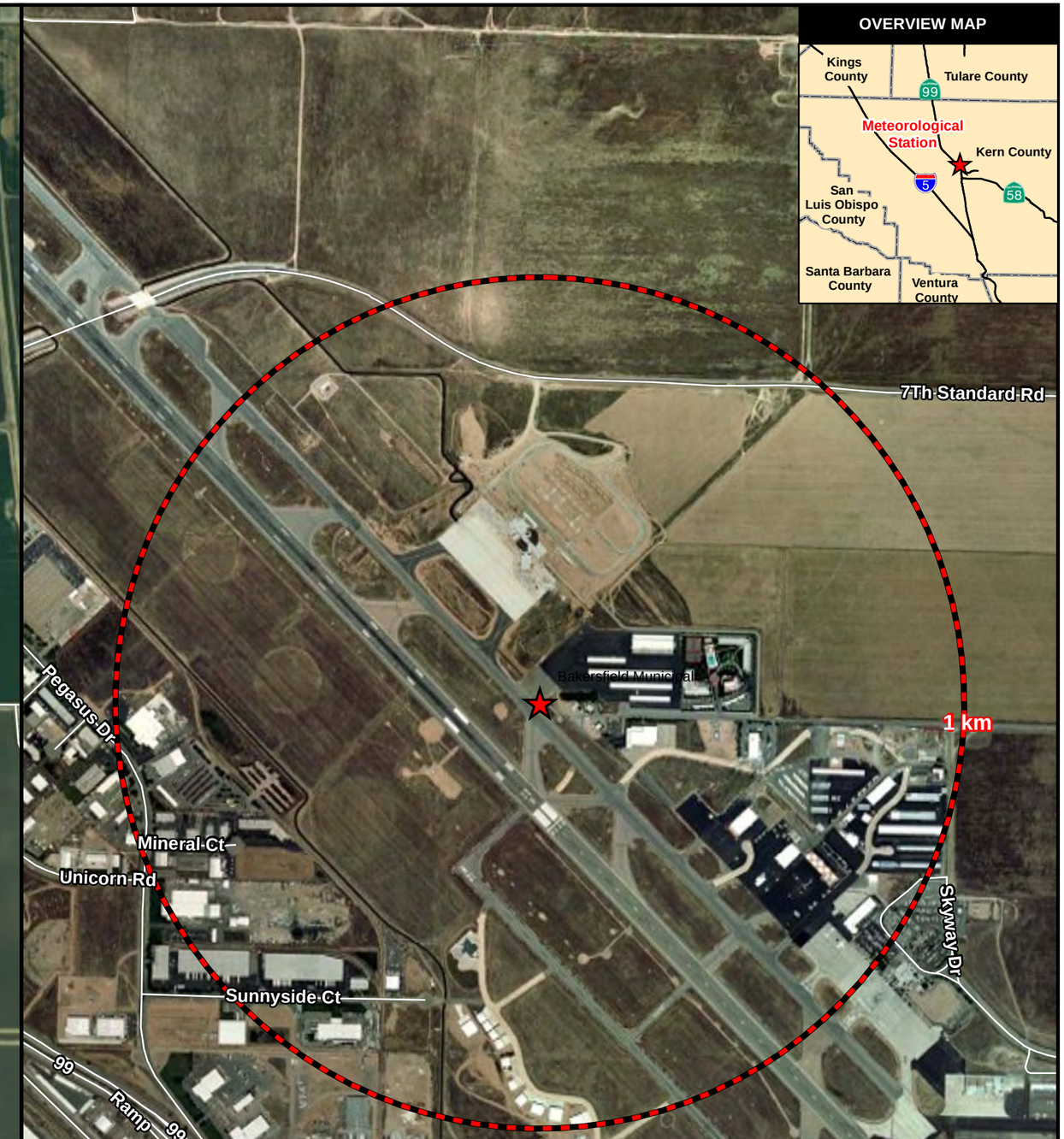

SOURCES:
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Roads (ESRI)

Meteorological Station at
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URS

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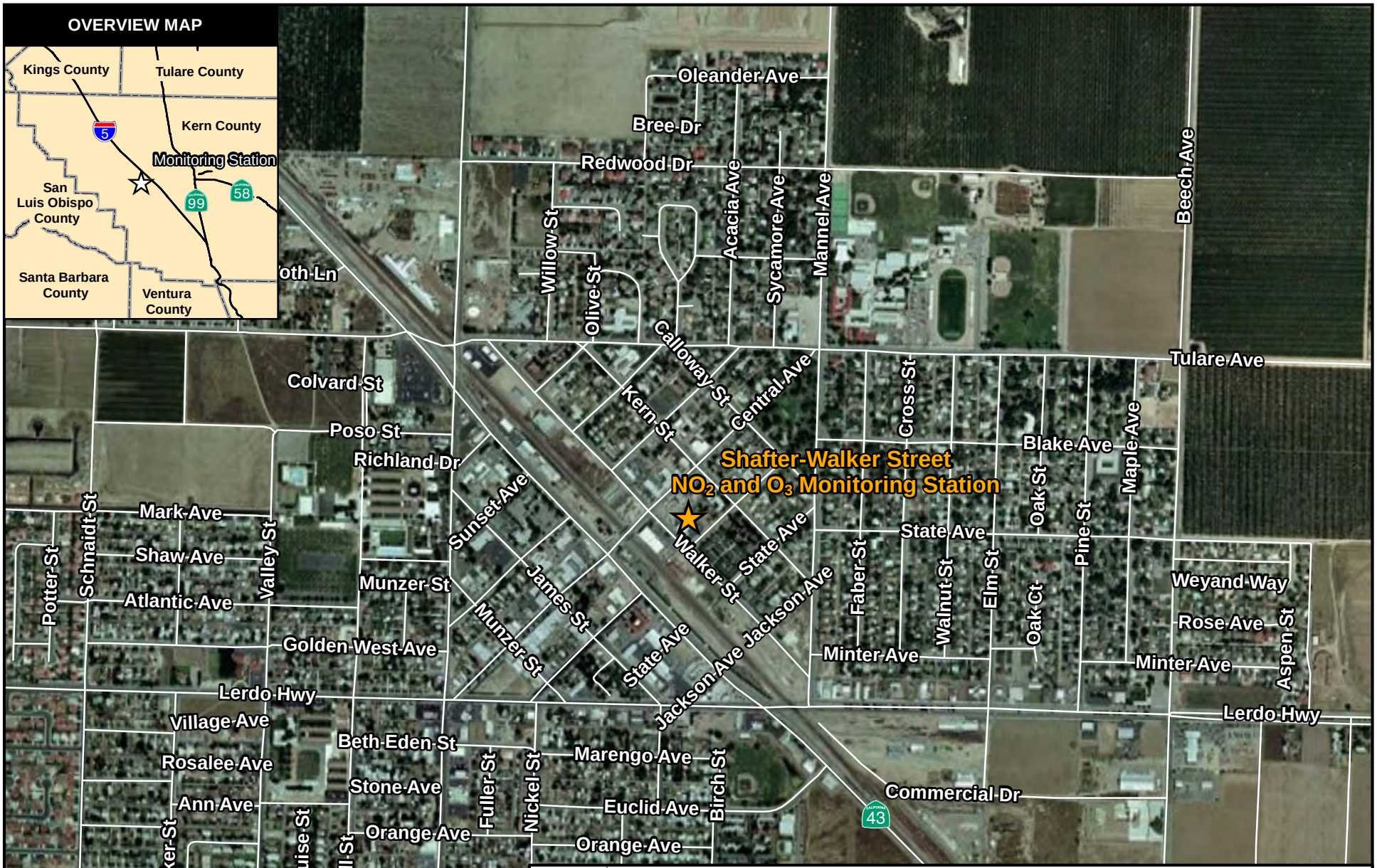

SOURCES:
NO_2 and O_3 Monitoring Station (URS, 2010)
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NO_2 and O_3 Monitoring Station
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NO_2 and O_3 Monitoring Station
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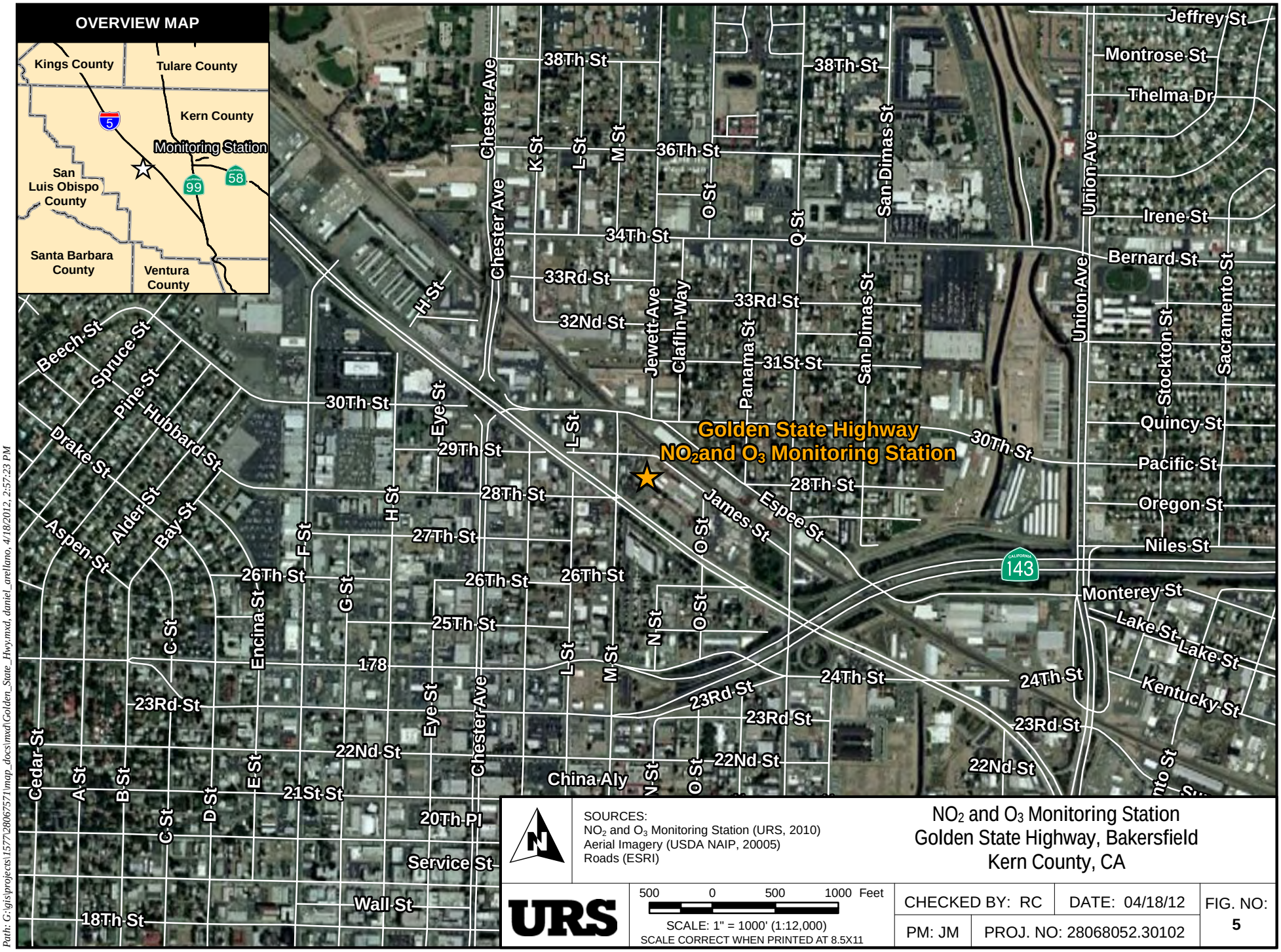

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Kern County, CA

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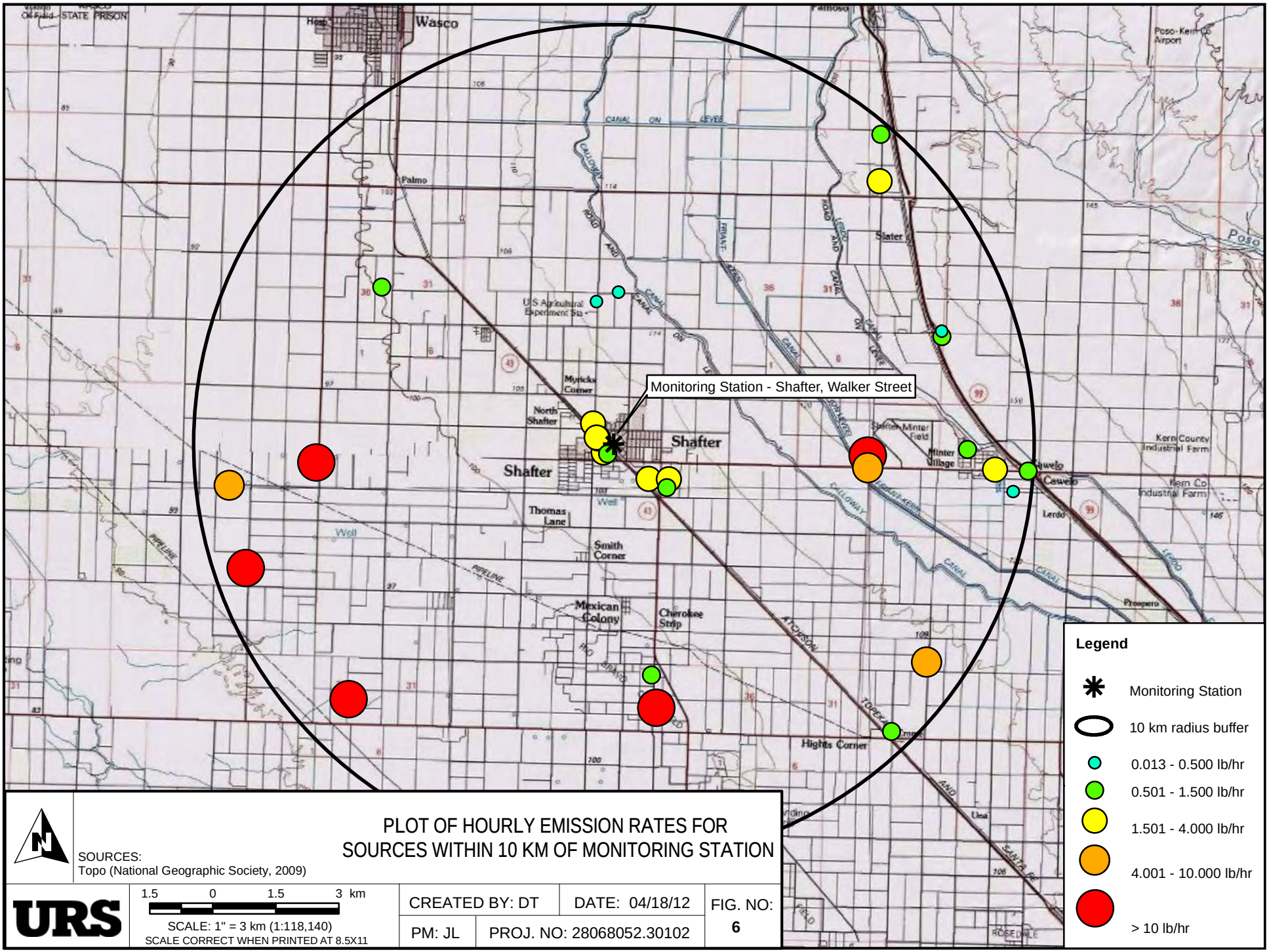

PLOT OF HOURLY EMISSION RATES FOR SOURCES WITHIN 10 KM OF MONITORING STATION

SOURCES:
Topo (National Geographic Society, 2009)

URS

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SCALE: 1" = 3 km (1:118,140)
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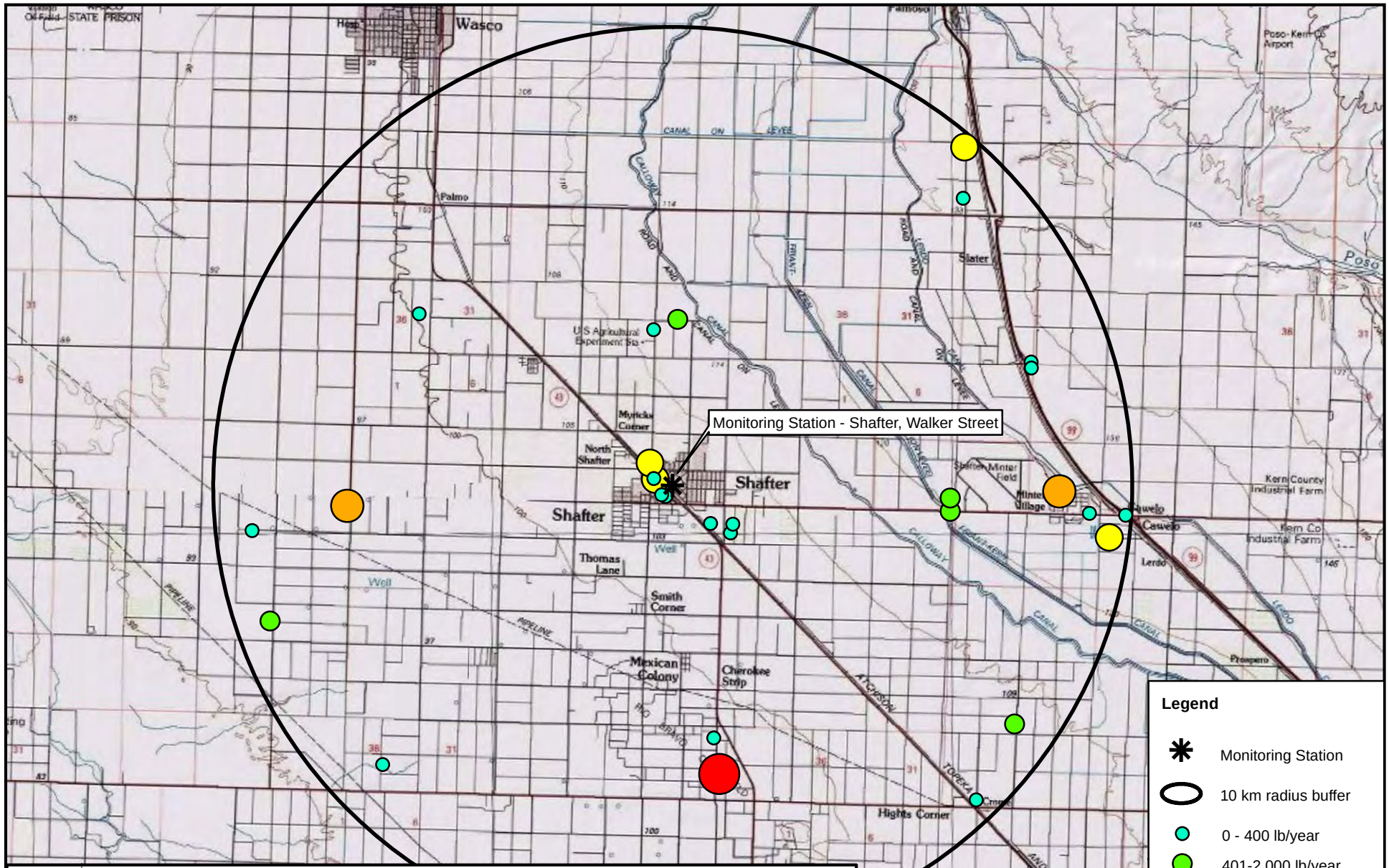

SOURCES:
Topo (National Geographic Society, 2009)

PLOT OF ANNUAL EMISSION RATES FOR SOURCES WITHIN 10 KM OF MONITORING STATION

URS

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SCALE: 1" = 3 km (1:118,140)
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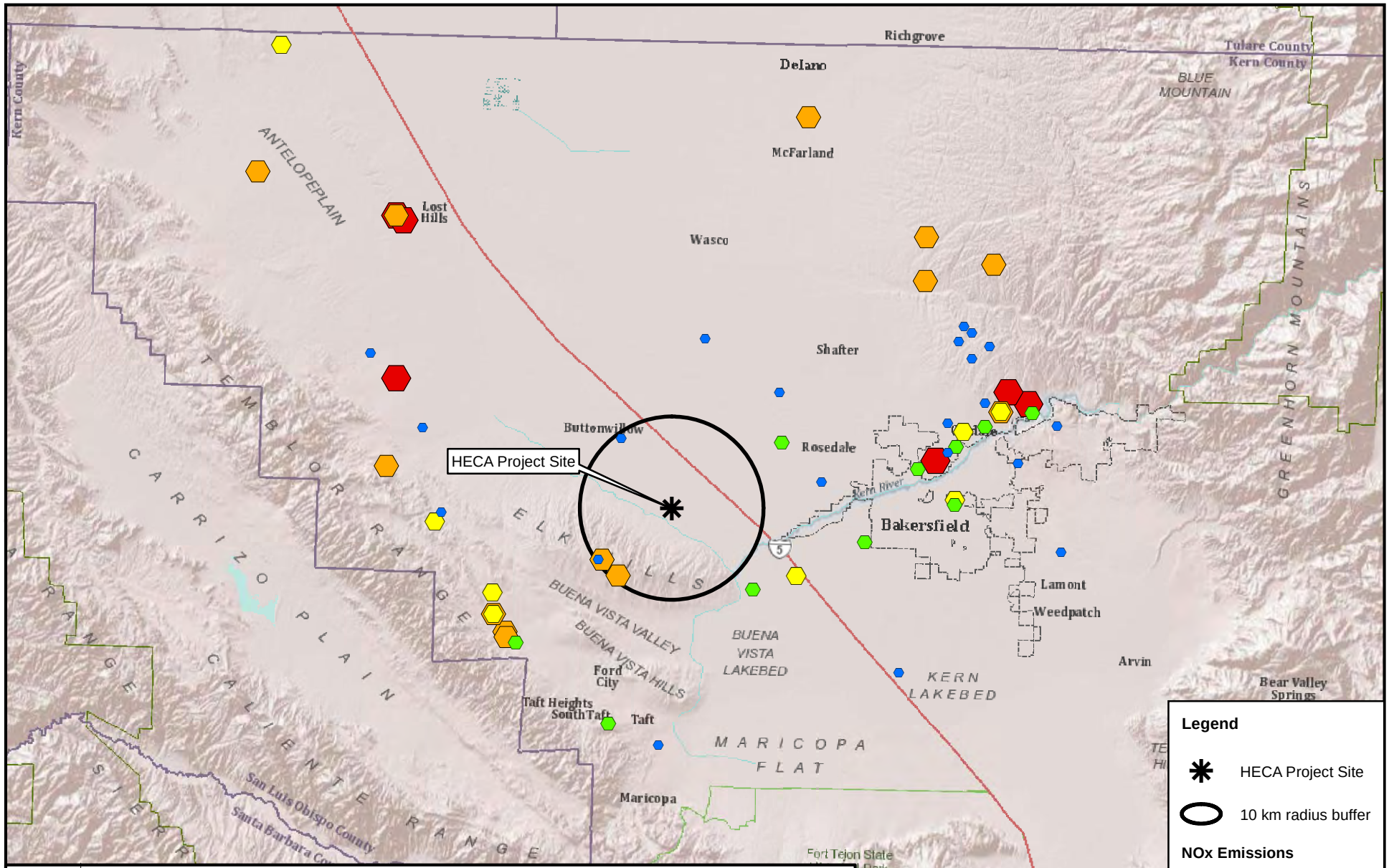

SOURCES:
ESRI (2012)

PLOT OF HOURLY EMISSION RATES FOR SOURCES WITHIN 60 KM OF PROJECT SITE

URS

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Attachment A

HECA Nearby Sources to 75 km included in the Regional Modeling Analysis

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1135	AERA ENERGY LLC	115	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR #1 (NEELY LEASE)	147.00	882	264.500	3898.000	265.170	3898.286	22.7	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	1.18	0.02	62.5	MMBtu/hr	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBtu/hr NG Boiler/Steam Gen	6.13	7.32	421.89	5.51	1.07	B1135A15
1135	AERA ENERGY LLC	119	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR #5 WITH NORTH AMERICAN BURNER (ANDERSON GOODWIN LEASE)	147.00	882	264.500	3898.500	265.170	3898.286	22.7	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	1.18	0.02	62.5	MMBtu/hr	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBtu/hr NG Boiler/Steam Gen	6.13	7.32	421.89	5.51	1.07	B1135A19
1135	AERA ENERGY LLC	122	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR #6 WITH NORTH AMERICAN BURNER (ANDERSON GOODWIN LEASE)	147.00	882	265.000	3898.000	265.170	3898.286	22.7	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	1.18	0.02	62.5	MMBtu/hr	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBtu/hr NG Boiler/Steam Gen	6.13	7.32	421.89	5.51	1.07	B1135A22
1135	AERA ENERGY LLC	123	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR #7 WITH NORTH AMERICAN BURNER (ANDERSON GOODWIN LEASE)	147.00	882	265.000	3898.500	265.170	3898.286	22.7	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	1.18	0.02	62.5	MMBtu/hr	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBtu/hr NG Boiler/Steam Gen	6.13	7.32	421.89	5.51	1.07	B1135A23
1547	AERA ENERGY LLC	144	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR WITH A COEN QLN-ULN LOW NOX BURNER, FLUE GAS RECIRCULATION, AND SHARED SO2 SCRUBBER LISTED ON S-1547-141, (#129 DIS# 28613-82) (A/F DEHY)	54.00	9,855	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.15	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547A44
1547	AERA ENERGY LLC	190	62.5 MMBTU/HR NATURAL GAS/TEOR GAS-FIRED STEAM GENERATOR WITH A COEN ULN BURNER, FLUE GAS RECIRCULATION, VAPOR RECOVERY PIPING FROM S-1135-21, AND APPROVED TO OPERATE AT VARIOUS SPECIFIED LOCATIONS (BUENA FE #6, DIS# 4624-82)	54.00	19,710	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.30	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547A90
1547	AERA ENERGY LLC	241	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR, WITH MITSUBISHI LO-NOX BURNER, STAGED COMBUSTION, FLUE GAS RECIRCULATION AND VAPOR PIPING FROM S-1547-707, (#100, DIS# 28692-82) (D&E SANDS)	54.00	9,855	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.15	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547B41
1547	AERA ENERGY LLC	243	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR, WITH MITSUBISHI LO-NOX BURNER, STAGED COMBUSTION, FLUE GAS RECIRCULATION AND VAPOR PIPING FROM S-1547-707, (#102, DIS# 28732-83) (D&E SANDS)	54.00	9,855	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.15	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547B43
1547	AERA ENERGY LLC	244	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR, WITH MITSUBISHI LO-NOX BURNER, STAGED COMBUSTION, FLUE GAS RECIRCULATION AND VAPOR PIPING FROM S-1547-707, (#103, DIS# 28694-82) (D&E SANDS)	54.00	9,855	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.15	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547B44
1547	AERA ENERGY LLC	683	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR, WITH FLUE GAS RECIRCULATION (W-10, DIS# 34142-93, S.N. 51106-01) (WIER #10)	54.00	1,080	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.02	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547F83
1547	AERA ENERGY LLC	684	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR, WITH FLUE GAS RECIRCULATION (DIS# 34141-93, S.N. 51106-02) (WIER #9)	54.00	1,080	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.02	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547F84
1547	AERA ENERGY LLC	751	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH A COEN MODEL #QLN-ULN 3.2, FLUE GAS RECIRCULATION (FGR) SYSTEM (SHALE #5, NORTH MIDWAY)	52.80	9,636	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.29	0.15	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.20	7.32	421.89	5.51	1.07	B1547G51

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1547	AERA ENERGY LLC	754	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH A COEN ULN BURNER, FLUE GAS RECIRCULATION, AND NON-CONDENSABLE PIPING FROM VAPOR CONTROL SYSTEM S-1547-359. (#2-5A) (BELRIDGE)	52.80	9,636	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.29	0.15	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.20	7.32	421.89	5.51	1.07	B1547G54
1547	AERA ENERGY LLC	761	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR, WITH A COEN ULN BURNER, FLUE GAS RECIRCULATION, AND NON-CONDENSIBLE PIPING FROM VAPOR CONTROL SYSTEM S-1547-359. (#3-2M) (BELRIDGE)	52.80	8,541	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.29	0.13	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.20	7.32	421.89	5.51	1.07	B1547G61
1547	AERA ENERGY LLC	764	62.5 MMBTU/HR C.E. NATCO NATURAL GAS FIRED STEAM GENERATOR, WITH A COEN ULN LOW NOX BURNER AND FLUE GAS RECIRCULATION (MOCO #804) (SOUTH MIDWAY)	1,095.00	9,855	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. The short term emission rate of 1095 lb/day, as provided by SJVAPCD, is believed to be in error, as it is not consistent with similar sources at this or other facilities. Therefore an emission rate of 53 lb/day was used.	6.03	0.15	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.20	7.32	421.89	5.51	1.07	B1547G64
1547	AERA ENERGY LLC	798	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH COEN ULN LOW NOX BURNER AND FLUE GAS RECIRCULATION (FGR) SYSTEM (SHALE #2, NORTH MIDWAY)	54.00	9,460	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.14	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547G98
1547	AERA ENERGY LLC	799	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH COEN ULN LOW NOX BURNER AND FLUE GAS RECIRCULATION (FGR) SYSTEM (SHALE #3, NORTH MIDWAY)	51.00	9,461	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.28	0.14	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.13	7.32	421.89	5.51	1.07	B1547G99
1547	AERA ENERGY LLC	800	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH COEN ULN LOW NOX BURNER AND FLUE GAS RECIRCULATION (FGR) SYSTEM [SHALE #4, NORTH MIDWAY)	54.00	9,460	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.14	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547H00
1547	AERA ENERGY LLC	801	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH COEN QLN-ULN BURNER AND FLUE GAS RECIRCULATION (SHALE #6, NORTH MIDWAY)	51.00	9,461	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.28	0.14	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.13	7.32	421.89	5.51	1.07	B1547H01
1547	AERA ENERGY LLC	805	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH COEN QLN-ULN LOW NOX BURNER AND FLUE GAS RECIRCULATION (FINLEY #9, NORTH MIDWAY)	54.00	9,460	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.14	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547H05
1547	AERA ENERGY LLC	806	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR WITH COEN ULN BURNER AND FLUE GAS RECIRCULATION (FINLEY #10, NORTH MIDWAY)	54.00	9,460	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.14	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547H06
1547	AERA ENERGY LLC	808	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS- FIRED STEAM GENERATOR WITH A COEN, MODEL ULN, LOW NOX BURNER, A FLUE GAS RECIRCULATION SYSTEM AND NON-CONDENSIBLE PIPING FROM VAPOR CONTROL SYSTEM (#11-1H) (BELRIDGE)	51.00	18,615	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.28	0.28	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.13	7.32	421.89	5.51	1.07	B1547H08
1547	AERA ENERGY LLC	812	62.5 MMBTU/HR NATURAL GAS (AND VAPOR RECOVERY GAS) FIRED STEAM GENERATOR WITH A COEN MODEL QLN-ULN BURNER AND FLUE GAS RECIRCULATION (MOCO #807) (SOUTH MIDWAY)	51.00	18,615	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.28	0.28	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.13	7.32	421.89	5.51	1.07	B1547H12
1547	AERA ENERGY LLC	826	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH COEN QLN-ULN BURNER AND FLUE GAS RECIRCULATION (FINLEY #8, NORTH MIDWAY)	51.00	9,461	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.28	0.14	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.13	7.32	421.89	5.51	1.07	B1547H26

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1547	AERA ENERGY LLC	827	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH COEN ULN LOW NOX BURNER AND FLUE GAS RECIRCULATION (FGR) SYSTEM [FINLEY #11, NORTH MIDWAY)	54.00	9,855	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.15	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547H27
1547	AERA ENERGY LLC	828	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH COEN ULN LOW NOX BURNER AND FLUE GAS RECIRCULATION (FINLEY #12, NORTH MIDWAY)	54.00	9,856	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.15	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547H28
1547	AERA ENERGY LLC	829	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH A COEN MODEL QLN-ULN LOW NOX BURNER, FLUE GAS RECIRCULATION (FGR) AND NON-CONDENSIBLE PIPING FROM VAPOR CONTROL SYSTEM (FINLEY #13, NORTH MIDWAY)	54.00	9,460	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.30	0.14	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1547H29
1547	AERA ENERGY LLC	831	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR WITH A COEN MODEL QLN-ULN LOW-NOX BURNER, FLUE GAS RECIRCULATION AND NON-CONDENSIBLE PIPING FROM VAPOR CONTROL SYSTEM, (MOCO #809) (SOUTH MIDWAY)	51.00	18,615	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.28	0.28	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.13	7.32	421.89	5.51	1.07	B1547H31
1547	AERA ENERGY LLC	885	62.5 MMBTU/HR NATURAL GAS (AND VAPOR RECOVERY GAS) FIRED STEAM GENERATOR WITH A COEN ULN BURNER AND FLUE GAS RECIRCULATION (MOCO #803) (SOUTH MIDWAY)	51.00	18,615	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.28	0.28	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.13	7.32	421.89	5.51	1.07	B1547H85
1547	AERA ENERGY LLC	886	62.5 MMBTU/HR NATURAL GAS (AND VAPOR RECOVERY GAS) FIRED STEAM GENERATOR WITH A COEN ULN BURNER AND FLUE GAS RECIRCULATION (MOCO #801) (SOUTH MIDWAY)	51.00	18,615	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.28	0.28	62.5	MMBTU/HR	NG	AeraEnergy	Boiler/Steam Gen	0.1	AeraEnergy 62.5 MMBTU/HR NG Boiler/Steam Gen	2.13	7.32	421.89	5.51	1.07	B1547H86
1135	AERA ENERGY LLC	15	2.5 MW COMBINED CYCLE GAS TURBINE TOPPING CYCLE COGENERATION UNIT TG-1 INCLUDING SOLAR TURBINE INC. CENTAUR MODEL GSC-400G, 38.5 MMBTU/HR GAS FIRED TURBINE ENGINE AND 2.5 MW ELECTRICAL GENERATOR (MAXWELL LEASE)	119.10	43,473	265.070	3898.286	265.170	3898.286	22.7	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.96	0.96	2.5	MW	NG	AeraEnergy	Turbine-Small	0.1032	AeraEnergy 2.5 MW NG Turbine-Small	4.96	13.00	710.22	6.15	1.57	C1135_15
1135	AERA ENERGY LLC	224	75 MW COGENERATION UNIT A WITH GE MODEL G7111E FRAME 7E GAS TURBINE ENGINE WITH DRY LOW NOX COMBUSTORS AND SELECTIVE CATALYTIC REDUCTION (SCR) AND UNFIRED HEAT RECOVERY STEAM GENERATOR (HRSG)	423.90	154,724	265.170	3898.386	265.170	3898.286	22.7	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro, except temp assumed same as that used for Frito 6 MW cogen (also based on assumptions). Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	3.41	3.41	75	MW	NG	AeraEnergy	Turbine-Large	0.17	AeraEnergy 75 MW NG Turbine-Large	17.66	15.24	367.44	13.03	3.42	C1135B24
1135	AERA ENERGY LLC	225	75 MW COGENERATION UNIT B WITH GE MODEL G7111E FRAME 7E GAS TURBINE ENGINE WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION (SCR), AND UNFIRED HEAT RECOVERY STEAM GENERATOR (HRSG)	423.90	154,724	265.170	3898.286	265.170	3898.286	22.7	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro, except temp assumed same as that used for Frito 6 MW cogen (also based on assumptions). Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	3.41	3.41	75	MW	NG	AeraEnergy	Turbine-Large	0.17	AeraEnergy 75 MW NG Turbine-Large	17.66	15.24	367.44	13.03	3.42	C1135B25
1135	AERA ENERGY LLC	226	75 MW COGENERATION UNIT C WITH GE MODEL G7111E FRAME 7E GAS TURBINE ENGINE WITH DRY LOW NOX COMBUSTORS AND SELECTIVE CATALYTIC REDUCTION (SCR) AND UNFIRED HEAT RECOVERY STEAM GENERATOR (HRSG)	423.90	154,724	265.170	3898.186	265.170	3898.286	22.7	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro, except temp assumed same as that used for Frito 6 MW cogen (also based on assumptions). Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	3.41	3.41	75	MW	NG	AeraEnergy	Turbine-Large	0.17	AeraEnergy 75 MW NG Turbine-Large	17.66	15.24	367.44	13.03	3.42	C1135B26
1547	AERA ENERGY LLC	148	21.45 MW GAS FIRED TURBINE ENGINE COGENERATION FACILITY #1 WITH GENERAL ELECTRIC MODEL LM2500 PE GAS TURBINE AND UNFIRED WASTE HEAT RECOVERY STEAM GENERATOR: RETROFIT THE UNFIRED WASTE HEAT RECOVERY STEAM GENERATOR AND THE BYPASS STACK WITH SELECTIVE CATA	190.20	69,424	253.200	3926.500	253.200	3926.500	33.1	Height, velocity, diam assumed same as 38.7 MW Berry plant, except temp assumed same as that used for Frito 6 MW cogen.	1.05	1.05	21.45	MW	NG	AeraEnergy	Turbine-Large	0.17	AeraEnergy 21.45 MW NG Turbine-Large	7.93	15.24	367.44	13.03	3.42	C1547A48
1547	AERA ENERGY LLC	149	21.45 MW GAS FIRED TURBINE ENGINE COGENERATION FACILITY #2 WITH GENERAL ELECTRIC MODEL LM2500 PE GAS TURBINE, UNFIRED WASTE HEAT RECOVERY STEAM GENERATOR EQUIPPED WITH SCR AND AMMONIA INJECTION, AND BYPASS STACK EQUIPPED WITH SCR AND AMMONIA INJECTION	62.70	22,667	253.200	3926.500	253.200	3926.500	33.1	Height, velocity, diam assumed same as 38.7 MW Berry plant, except temp assumed same as that used for Frito 6 MW cogen.	0.35	0.34	21.45	MW	NG	AeraEnergy	Turbine-Large	0.17	AeraEnergy 21.45 MW NG Turbine-Large	2.61	15.24	367.44	13.03	3.42	C1547A49

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1547	AERA ENERGY LLC	151	21.45 MW GAS FIRED TURBINE ENGINE COGENERATION FACILITY #3 WITH GENERAL ELECTRIC MODEL LM2500 PE GAS TURBINE, UNFIRED WASTE HEAT RECOVERY STEAM GENERATOR EQUIPPED WITH SCR AND AMMONIA INJECTION, AND BYPASS STACK EQUIPPED WITH SCR AND AMMONIA INJECTION	62.10	22,667	253.200	3926.500	253.200	3926.500	33.1	Height, velocity, diam assumed same as 38.7 MW Berry plant, except temp assumed same as that used for Frito 6 MW cogen.	0.34	0.34	21.45	MW	NG	AeraEnergy	Turbine-Large	0.17	AeraEnergy 21.45 MW NG Turbine-Large	2.59	15.24	367.44	13.03	3.42	C1547A51
1547	AERA ENERGY LLC	459	4 MW ALLISON MODEL 501 KB5 NATURAL GAS-FIRED TURBINE ENGINE COGENERATION SYSTEM INCLUDING: GAS COMPRESSION SYSTEM, INLET AIR EVAPORATIVE COOLER, NOX CONTROL WATER INJECTION SYSTEM, AND STEAM GENERATOR PRODUCING 80% QUALITY STEAM AT 800 PSIG (WIER - NORTH	142.30	51,940	253.200	3926.500	253.200	3926.500	33.1	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	0.78	0.78	4	MW	NG	AeraEnergy	Turbine-Small	0.1032	AeraEnergy 4 MW NG Turbine-Small	5.93	13.00	710.22	6.15	1.57	C1547D59
1547	AERA ENERGY LLC	879	SOLAR CENTAUR MODEL T4500, 3.2 MW, 61.5 MMBTU/HR HEAT INPUT, GAS-FIRED GAS TURBINE ENGINE/GENERATOR WITH INLET AIR EVAPORATIVE COOLER AND H2O INJECTION, 38.7 MMBTU/HR DUCT BURNER, AND S.C.R. WITH AMMONIA INJECTION. - BELRIDGE	64.80	23,652	253.200	3926.500	253.200	3926.500	33.1	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	0.36	0.36	3.2	MW	NG	AeraEnergy	Turbine-Small	0.1032	AeraEnergy 3.2 MW NG Turbine-Small	2.70	13.00	710.22	6.15	1.57	C1547H79
1547	AERA ENERGY LLC	880	SOLAR CENTAUR MODEL T4500, 3.2 MW, 61.5 MMBTU/HR HEAT INPUT, GAS-FIRED GAS TURBINE (COGEN UNIT #B) ENGINE/GENERATOR WITH INLET AIR EVAPORATIVE COOLER AND H2O INJECTION, 38.7 MMBTU/HR DUCT BURNER, AND S.C.R. WITH AMMONIA INJECTION. - BELRIDGE	64.80	23,652	253.200	3926.500	253.200	3926.500	33.1	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	0.36	0.36	3.2	MW	NG	AeraEnergy	Turbine-Small	0.1032	AeraEnergy 3.2 MW NG Turbine-Small	2.70	13.00	710.22	6.15	1.57	C1547H80
1547	AERA ENERGY LLC	881	SOLAR CENTAUR MODEL T4500, 3.2 MW, 61.5 MMBTU/HR HEAT INPUT, GAS-FIRED GAS TURBINE (COGEN UNIT #C) ENGINE/GENERATOR WITH INLET AIR EVAPORATIVE COOLER, H2O INJECTION, 38.7 MMBTU/HR DUCT BURNER, AND S.C.R. WITH AMMONIA INJECTION. - BELRIDGE	64.80	23,652	253.200	3926.500	253.200	3926.500	33.1	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	0.36	0.36	3.2	MW	NG	AeraEnergy	Turbine-Small	0.1032	AeraEnergy 3.2 MW NG Turbine-Small	2.70	13.00	710.22	6.15	1.57	C1547H81
1543	AERA ENERGY LLC	33	3,600 MMBTU/HR KALDAIR INDAIR LIMITED USE PRODUCED GAS FLARE WITH COANDA EFFECT FLARE TIP	4,081.00	6,492	253.200	3926.495	253.200	3926.495	33.1	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	22.47	0.10	3,600	MMBTU/HR	NG	AeraEnergy	Flare	0.1	AeraEnergy 3600 MMBTU/HR NG Flare	170.04	87.30	1273.00	20.00	10.52	F1543_33
1547	AERA ENERGY LLC	414	60 MMBTU/HR KALDAIR MODEL P-20-E PIPE STANDBY FLARE, SULFA TREAT VESSEL, AND GAS HYDRATING AND DRAIN SYSTEM (A/F DEHY)	168.00		253.200	3926.500	253.200	3926.500	33.1	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	0.92	-	60	MMBTU/HR	NG	AeraEnergy	Flare	0.1	AeraEnergy 60 MMBTU/HR NG Flare	7.00	19.68	1273.00	20.00	1.36	F1547D14
1548	AERA ENERGY LLC	134	625 MMBTU/HR LIMITED USE FLARE	1,020.00	6,063	253.999	3943.740	253.999	3943.740	42.9	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	4.34	0.07	625	MMBTU/HR	NG	AeraEnergy	Flare	0.1	AeraEnergy 625 MMBTU/HR NG Flare	42.50	33.48	1273.00	20.00	4.38	F1548A34
1548	AERA ENERGY LLC	144	12,000 BBL FIXED ROOF CLARIFIER TANK 201A W/VAPOR CONTROL COMPRESSOR(S), COOLER(S), LIQUID KNOCKOUT(S) & PIPING TO FIELD GAS SYSTEM OR AIR ASSISTED KALDAIR FLARE W/PLA-18 FLARE TIP	340.00	6,800	253.999	3943.740	253.999	3943.740	42.9	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares. Heat input rating borrowed from similar Chevron facility source F1141E13, as one not provided.	1.45	0.08	167	MMBTU/HR	vapor	AeraEnergy	Flare	0.1	AeraEnergy 167 MMBTU/HR vapor Flare	14.17	23.90	1273.00	20.00	2.27	F1548A44
1548	AERA ENERGY LLC	389	223,125,000 BTU/HR COANDA EFFECT SAFETY FLARE (WESTSIDE)	364.00	6,063	253.999	3943.740	253.999	3943.740	42.9	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	1.55	0.07	223	MMBTU/HR	NG	AeraEnergy	Flare	0.1	AeraEnergy 223.125 MMBTU/HR NG Flare	15.17	25.52	1273.00	20.00	2.62	F1548C89
1548	AERA ENERGY LLC	424	825 MMBTU/HR KALDAIR INDAIR MODEL I-15-H-VS LIMITED USE FLARE WITH COANDA EFFECT FLARE TIP (COMPRESSOR STATION 49)	1,346.40	6,063	253.999	3943.740	253.999	3943.740	42.9	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	5.73	0.07	825	MMBTU/HR	NG	AeraEnergy	Flare	0.1	AeraEnergy 825 MMBTU/HR NG Flare	56.10	36.39	1273.00	20.00	5.04	F1548D24
1543	AERA ENERGY LLC	5	13.6 MMBTU/HR GAS FIRED SOLAR SATURN GAS TURBINE ENGINE/COMPRESSOR WITH GAS FIRED 5.9 MMBTU/HR DUCT BURNER DRIVING GAS COMPRESSOR - OPERATION A	106.60	38,909	253.200	3926.495	253.200	3926.495	33.1	Stack parameters assumed same as that used for Frito 6 MW cogen (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	0.59	0.59	13.6	MMBTU/HR	NG	AeraEnergy	Turbine-Small	0.17	AeraEnergy 13.6 MMBTU/HR NG Turbine-Small	4.44	13.00	710.22	6.15	1.57	G1543_5

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1547	AERA ENERGY LLC	1068	140 BHP DETROIT-ALLISON MODEL #50437001 DIESEL-FIRED IC ENGINE USED TO START A GAS TURBINE	74.10	3,086	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.41	0.05	140	BHP	diesel	AeraEnergy	IC Engine_Turb	0.2	AeraEnergy 140 BHP diesel IC Engine_Turb	3.09	3.00	622.00	53.20	0.08	S1547J68
1547	AERA ENERGY LLC	1069	140 BHP DETROIT-ALLISON MODEL #50437001 DIESEL-FIRED IC ENGINE USED TO START A GAS TURBINE	74.10	3,086	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.41	0.05	140	BHP	diesel	AeraEnergy	IC Engine_Turb	0.2	AeraEnergy 140 BHP diesel IC Engine_Turb	3.09	3.00	622.00	53.20	0.08	S1547J69
1547	AERA ENERGY LLC	1070	140 BHP DETROIT-ALLISON MODEL #50437001 DIESEL-FIRED IC ENGINE USED TO START A GAS TURBINE	74.10	3,086	253.200	3926.500	253.200	3926.500	33.1	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.41	0.05	140	BHP	diesel	AeraEnergy	IC Engine_Turb	0.2	AeraEnergy 140 BHP diesel IC Engine_Turb	3.09	3.00	622.00	53.20	0.08	S1547J70
1547	AERA ENERGY LLC	1060	3.5 MW COMBINED CYCLE GAS TURBINE TOPPING CYCLE COGENERATION LOST HILLS UNIT #4	150.70	54,990	253.200	3926.500	253.200	3926.500	33.1	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	0.83	0.83	3.5	MW	NG	AeraEnergy	Turbine-Small	0.1032	AeraEnergy 3.5 MW NG Turbine-Small	6.28	13.00	710.22	6.15	1.57	T1547J60
1547	AERA ENERGY LLC	1061	3.5 MW COMBINED CYCLE GAS TURBINE TOPPING CYCLE COGENERATION LOST HILLS UNIT #5	150.70	54,990	253.200	3926.500	253.200	3926.500	33.1	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	0.83	0.83	3.5	MW	NG	AeraEnergy	Turbine-Small	0.1032	AeraEnergy 3.5 MW NG Turbine-Small	6.28	13.00	710.22	6.15	1.57	T1547J61
1547	AERA ENERGY LLC	1062	3.5 MW COMBINED CYCLE GAS TURBINE TOPPING CYCLE COGENERATION LOST HILLS UNIT #6	150.70	54,990	253.200	3926.500	253.200	3926.500	33.1	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	0.83	0.83	3.5	MW	NG	AeraEnergy	Turbine-Small	0.1032	AeraEnergy 3.5 MW NG Turbine-Small	6.28	13.00	710.22	6.15	1.57	T1547J62
1250	BADGER CREEK LIMITED	1	48.5 MW COGENERATION SYSTEM WITH SCR INCLUDING STEWART & STEVENSON GE MODEL 5000 GAS-FIRED TURBINE, HEAT RECOVERY STEAM GENERATOR, AND INLET AIR ABSORPTION CHILLER AND HEAT EXCHANGER	147.90	53,984	315.860	3928.587	315.860	3928.587	36.6	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run, except temp assumed same as that used for Frito 6 MW cogen	0.74	0.74	48.5	MW	NG	BadgerCkLtd	Turbine-Large	0.17	BadgerCkLtd 48.5 MW NG Turbine-Large	6.16	15.24	367.44	13.03	3.42	C1250_1
2049	BEAR MOUNTAIN LIMITED	1	NOMINALLY RATED 48 MW G.T.E. COGENERATION SYSTEM WITH SCR, INCLUDING STEWART AND STEVENSON GE LM-5000 GAS TURBINE GENERATOR, HEAT RECOVERY STEAM GENERATOR, AND INLET AIR ABSORPTION CHILLER AND HEAT EXCHANGER	143.70	52,451	325.097	3921.234	325.097	3921.234	43.0	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run, except temp assumed same as that used for Frito 6 MW cogen	0.61	0.61	48	MW	NG	BearMtnLtd	Turbine-Large	0.17	BearMtnLtd 48 MW NG Turbine-Large	5.99	15.24	367.44	13.03	3.42	C2049_1
4692	BELLANAVE CORPORATION	10	375 BHP CATERPILLAR MODEL C-11 SN GLS00104 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL PUMP (WELL #3)	129.00	11,177	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	1.53	0.36	375	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 375 BHP diesel IC Engine_Pump	5.38	3.00	622.00	76.60	0.13	P4692_10
4692	BELLANAVE CORPORATION	13	400 BHP CATERPILLAR MODEL C-13 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL PUMP	137.60	11,922	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	1.63	0.39	400	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 400 BHP diesel IC Engine_Pump	5.73	3.00	622.00	76.60	0.13	P4692_13
4692	BELLANAVE CORPORATION	14	400 BHP CATERPILLAR MODEL C-12 SN LGK00252 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL PUMP	137.60	11,922	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	1.63	0.39	400	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 400 BHP diesel IC Engine_Pump	5.73	3.00	622.00	76.60	0.13	P4692_14
4692	BELLANAVE CORPORATION	15	400 BHP CATERPILLAR MODEL C-12 SN LGK00260 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL PUMP	137.60	11,922	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	1.63	0.39	400	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 400 BHP diesel IC Engine_Pump	5.73	3.00	622.00	76.60	0.13	P4692_15

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
4692	BELLANAVE CORPORATION	19	385 BHP CATERPILLAR MODEL C13 SN LGK00245 TIER 3 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL IRRIGATION PUMP (WELL #1)	54.80	8,219	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.65	0.27	385	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 385 BHP diesel IC Engine_Pump	2.28	3.00	622.00	76.60	0.13	P4692_19
4692	BELLANAVE CORPORATION	20	385 BHP CATERPILLAR MODEL C13 SN LGK00253 TIER 3 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL IRRIGATION PUMP (WELL #2)	54.80	8,219	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.65	0.27	385	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 385 BHP diesel IC Engine_Pump	2.28	3.00	622.00	76.60	0.13	P4692_20
4692	BELLANAVE CORPORATION	21	385 BHP CATERPILLAR MODEL C13 SN LGK00258 TIER 3 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL IRRIGATION PUMP (WELL #8)	54.80	8,219	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.65	0.27	385	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 385 BHP diesel IC Engine_Pump	2.28	3.00	622.00	76.60	0.13	P4692_21
4692	BELLANAVE CORPORATION	22	385 BHP CATERPILLAR MODEL C13 SN LGK00261 TIER 3 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL IRRIGATION PUMP (WELL #10)	54.80	8,219	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.65	0.27	385	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 385 BHP diesel IC Engine_Pump	2.28	3.00	622.00	76.60	0.13	P4692_22
4692	BELLANAVE CORPORATION	23	385 BHP CATERPILLAR MODEL C13 SN LGK00249 TIER 3 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL IRRIGATION PUMP (WELL #9)	54.80	8,219	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.65	0.27	385	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 385 BHP diesel IC Engine_Pump	2.28	3.00	622.00	76.60	0.13	P4692_23
4692	BELLANAVE CORPORATION	24	385 BHP CATERPILLAR MODEL C13 SN LGK00263 TIER 3 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL IRRIGATION PUMP (WELL #11)	54.80	8,219	296.717	3904.937	296.717	3904.937	15.4	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.65	0.27	385	BHP	diesel	Bellanave	IC Engine_Pump	0.2	Bellanave 385 BHP diesel IC Engine_Pump	2.28	3.00	622.00	76.60	0.13	P4692_24
1246	BERRY PETROLEUM COMPANY	19	62.5 MMBTU/HR C.E. NATCO NATURAL/TEOR GAS-FIRED STEAM GENERATOR WITH FLUE GAS RECIRCULATION, NORTH AMERICAN LO-NOX BURNER, AND O2 CONTROLLER	54.00	19,710	276.270	3888.846	276.270	3888.846	24.3	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.40	0.40	62.5	MMBtu/hr	NG	BerryPetro	Boiler/Steam Gen	0.1	BerryPetro 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1246_19
1246	BERRY PETROLEUM COMPANY	252	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (#67) WITH NORTH AMERICAN, MODEL 6131-G, BURNER ASSEMBLY, FGR, AND OXYGEN ANALYZER/CONTROLLER	54.00	19,710	276.270	3888.846	276.270	3888.846	24.3	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.40	0.40	62.5	MMBtu/hr	NG	BerryPetro	Boiler/Steam Gen	0.1	BerryPetro 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1246B52
1246	BERRY PETROLEUM COMPANY	253	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (#68) WITH NORTH AMERICAN, MODEL 6131-G, BURNER ASSEMBLY, FGR, AND OXYGEN ANALYZER/CONTROLLER	54.00	19,710	276.270	3888.846	276.270	3888.846	24.3	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.40	0.40	62.5	MMBtu/hr	NG	BerryPetro	Boiler/Steam Gen	0.1	BerryPetro 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1246B53
1246	BERRY PETROLEUM COMPANY	254	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (#69) WITH NORTH AMERICAN, MODEL 6131-G, BURNER ASSEMBLY, FGR, AND OXYGEN ANALYZER/CONTROLLER	54.00	19,710	276.270	3888.846	276.270	3888.846	24.3	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.40	0.40	62.5	MMBtu/hr	NG	BerryPetro	Boiler/Steam Gen	0.1	BerryPetro 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1246B54
2265	BERRY PETROLEUM COMPANY	1	38.7 MW G.T.E. NATURAL GAS-FIRED COGENERATION SYSTEM - MIDWAY SUNSET FIELD	199.00	72,620	284.000	3893.997	284.000	3893.997	18.2	Height from sketch p.41 of 2006 test rpt in 1089099.pdf of DVD from SJVAPCD. Temp & diam, 2006 test rpt in 1089099.pdf. Exit velocity 2009 test rpt in 1404742.pdf of DVD from SJVAPCD	1.99	1.99	38.7	MW	NG	Berry	Turbine-Large	0.17	Berry 38.7 MW NG Turbine-Large	8.29	15.24	450.78	13.03	3.42	C2265_1
1246	BERRY PETROLEUM COMPANY	255	126,000 GALLON CRUDE OIL PRODUCTION TANK #T-101 (FORMAX LEASE) WITH TANK BATTERY VAPOR CONTROL SYSTEM AND STANDBY FLARE AS DESCRIBED IN S-1246-258	48.70	17,780	276.270	3888.846	276.270	3888.846	24.3	Assumed same size/stack parameters as safety flare at Oxy (F1216_87)	0.37	0.37		MMBtu/hr	Vapor	BerryPetro	Flare	0.1	BerryPetro MMBtu/hr Vapor Flare	2.03	18.80	1273.00	20.00	1.17	F1246B55

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
4751	BIDART DAIRY LLC	7	360 BHP CUMMINS MODEL P360 SN 60511629 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL PUMP	123.80	12,897	307.872	3894.409	307.872	3894.409	30.5	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.74	0.21	360	BHP	Diesel	BidartDairy	IC Engine_Pump	0.2	BidartDairy 360 BHP Diesel IC Engine_Pump	5.16	3.00	622.00	76.60	0.13	P4751_7
4751	BIDART DAIRY LLC	9	200 BHP CUMMINS MODEL 855 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL PUMP	68.80	2,866	307.872	3894.409	307.872	3894.409	30.5	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.41	0.05	200	BHP	Diesel	BidartDairy	IC Engine_Pump	0.2	BidartDairy 200 BHP Diesel IC Engine_Pump	2.87	3.00	622.00	59.90	0.10	P4751_9
33	BIG WEST OF CA, LLC	402	450 HP DETROIT DIESEL 8V-92TADDEC TRANSPORTABLE DIESEL-FIRED EMERGENCY I.C. ENGINE DRIVING AN AIR COMPRESSOR (ALSO PERMITTED AS S-34-49)	164.30	397	311.874	3917.500	311.874	3917.500	29.3	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	1.03	0.01	450	HP	Diesel	BigWest	IC Engine_Comp	0.2	BigWest 450 HP Diesel IC Engine_Comp	6.85	3.00	622.00	66.50	0.15	A33_402
33	BIG WEST OF CA, LLC	17	92 MMBTU/HR BOILER 81H1 WITH TODD VARIFLAME LOW NOX BURNER AND FGR - AREA 1	68.40	24,966	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.43	0.43	92	MMBtu/hr	NG	BigWest	Boiler/Steam Gen	0.32	BigWest 92 MMBtu/hr NG Boiler/Steam Gen	2.85	20.00	373.00	10.00	0.61	B33_17
33	BIG WEST OF CA, LLC	348	200 MMBTU/HR NATURAL GAS/REFINERY FUEL GAS FIRED BOILER 81-H9 WITH JOHN ZINK CMR LOW NOX BURNER AND A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM - AREA 2	52.80	19,272	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.33	0.33	200	MMBtu/hr	NG	BigWest	Boiler/Steam Gen	0.32	BigWest 200 MMBtu/hr NG Boiler/Steam Gen	2.20	20.00	373.00	10.00	0.91	B33_348
33	BIG WEST OF CA, LLC	59	42 MMBTU/HR NATURAL GAS/REFINERY GAS FIRED BOILER #81-H6 - AREA 2	131.40	47,961	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.82	0.82	42	MMBtu/hr	NG	BigWest	Boiler/Steam Gen	0.32	BigWest 42 MMBtu/hr NG Boiler/Steam Gen	5.48	20.00	373.00	10.00	0.30	B33_59
33	BIG WEST OF CA, LLC	61	78.8 MMBTU/HR NATURAL GAS/REFINERY GAS FIRED BOILER #81-H8 - AREA 2	245.90	89,754	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	1.53	1.53	78.8	MMBtu/hr	NG	BigWest	Boiler/Steam Gen	0.32	BigWest 78.8 MMBtu/hr NG Boiler/Steam Gen	10.25	20.00	373.00	10.00	0.61	B33_61
34	BIG WEST OF CA, LLC	42	98 MMBTU/HR NATURAL/REFINERY GAS FIRED BOILER (BOILER PLATE 84.8 MMBTU/HR)(81-H12) WITH TODD ULTRA LOW NOX BURNER AND FLUE GAS RECIRCULATION	84.70	25,754	313.610	3918.585	313.610	3918.585	31.2	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.50	0.41	98	MMBtu/hr	NG	BigWest	Boiler/Steam Gen	0.32	BigWest 98 MMBtu/hr NG Boiler/Steam Gen	3.53	20.00	373.00	10.00	0.61	B34_42
33	BIG WEST OF CA, LLC	11	HYDROTREATER UNIT #8 INCLUDING 12.8 MMBTU/HR GAS-FIRED CHARGE HEATER (8-H1) WITH JOHN ZINK COOLSTAR LOW NOX BURNER, REACTOR (8-R1), SEPARATOR (8-V2), 12.8 MMBTU/HR GAS-FIRED REBOILER HEATER (8-H2) WITH JOHN ZINK COOLSTAR LOW NOX BURNER, STRIPPER (8-V4), S	110.60	8,104	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.69	0.14	12.8	MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 12.8 MMBtu/hr NG Process Heaters_Dryers	4.61	20.00	366.33	10.00	1.22	H33_11
33	BIG WEST OF CA, LLC	12	CATALYTIC REFORMER #9 INCLUDING 4 REACTORS 9-R1, R2, R3 AND R4, 4 REFINERY FUEL GAS-FIRED HEATERS 38.5 MMBTU/HR 9-H1 AND 30.8 MMBTU/HR 9-H2 EACH WITH A CALLIDUS LOW NOX BURNER, 18.2 MMBTU/HR 9-H3 AND 9.2 MMBTU/HR 9-H4 EACH WITH A JOHN ZINK COOLSTAR LOW NO	461.30	33,655	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	2.88	0.58		MMBtu/hr	Vapor	BigWest	Process Heaters_Dryers	0.32	BigWest MMBtu/hr Vapor Process Heaters_Dryers	19.22	20.00	366.33	10.00	1.22	H33_12
33	BIG WEST OF CA, LLC	13	MILD HYDROCRACKER #14 INCLUDING 50 MMBTU/HR GAS FIRED CHARGE HEATER 14-H1, 40 MMBTU/HR GAS FIRED FEED HEATER 14-H2, REACTOR 14-R1, 4 SEPARATORS 14-04/5, V619, FRACTIONATOR 14-V1, DIESEL STRIPPER 14-V4 AND MISC PUMPS, HEAT EXCHANGERS, PIPING AND VESSELS -		58,867	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	-	1.01		MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest MMBtu/hr NG Process Heaters_Dryers	6.72	20.00	366.33	10.00	1.22	H33_13
33	BIG WEST OF CA, LLC	338	SULFUR RECOVERY UNIT #3 (SRU#3) INCLUDING TAIL GAS TREATING UNIT AND INCINERATOR (SHARED WITH UNIT S-33-16), AND MISCELLANEOUS TANKS, COMPRESSORS, PUMPS, H2S ANALYZERS, CONTROLLERS, HEAT EXCHANGERS, PIPING AND FILTERS	84.00	3,060	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.52	0.05		MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest MMBtu/hr NG Process Heaters_Dryers	3.50	20.00	366.33	10.00	1.22	H33_338

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
33	BIG WEST OF CA, LLC	49	161.4 MM BTU/HR CRUDE UNIT #11 INCLUDING HEATERS 11-H11, 11-H12, AND 11-H13, AND TOPPING ASSEMBLY - AREA 2	96.20	35,131	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.60	0.60	161.4	MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 161.4 MMBtu/hr NG Process Heaters_Dryers	4.01	20.00	366.33	10.00	1.22	H33_49
33	BIG WEST OF CA, LLC	52	86.8 MM BTU/HR CATALYTIC REFORMING UNIT #26 INCLUDING A DEPENTANIZER SERVICE TOWER (26-V13), REBOILER STEAM CONDENSATE BALANCE DRUM (26-D31), 2 FEED/BOTTOMS EXCHANGERS (26-E45 A/B), 2 OVERHEAD CONDENSERS (26-E46 A/B), DISTILLATE COOLER (26-E47), 2 BOTTOMS	374.90	136,866	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	2.34	2.34	86.8	MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 86.8 MMBtu/hr NG Process Heaters_Dryers	15.62	20.00	366.33	10.00	1.22	H33_52
33	BIG WEST OF CA, LLC	53	CATALYTIC REFORMING UNIT #4 (B REFORMER) INCLUDING A 65.0 MMBTU/HR HTR (22H11), 65.0 MMBTU/HR HTR (22H12), 34.7 MMBTU/HR HTR (22H13), 22.7 MMBTU/HR HTR (22H14), 25.0 MMBTU/HR HTR (22H15), & CATALYTIC & HYDROGEN GENERATION ASSEMBLYS - AREA 2		77,713	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	-	1.33	65	MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 65 MMBtu/hr NG Process Heaters_Dryers	8.87	20.00	366.33	10.00	1.22	H33_53
33	BIG WEST OF CA, LLC	55	HYDROGEN GENERATION UNIT INCLUDING 233 MMBTU/HR STEAM METHANE REFORMER FURNACE (20-H11) WITH RADIANT BURNERS AND A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM; JOHN ZINC INFURNOX INSERTS; CATALYTIC ASSEMBLY; AMINE ASSEMBLY WITH METHANOL ABSORBER COLUMN SER	61.50	22,451	311.874	3917.500	311.874	3917.500	29.3	Assumed stack height based on professional judgement (considering size and type of operation).	0.38	0.38	233	MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 233 MMBtu/hr NG Process Heaters_Dryers	2.56	20.00	366.33	10.00	1.22	H33_55
33	BIG WEST OF CA, LLC	56	HYDROCRACKER UNIT #21 INCLUDING 9 HEATERS , CATALYTIC ASSEMBLY , AND MISC AIR COOLERS, EXCHANGERS , DRUMS, AND PUMPS -AREA 2		190,363	311.874	3917.500	311.874	3917.500	29.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	-	3.25		MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest MMBtu/hr NG Process Heaters_Dryers	21.73	20.00	366.33	10.00	1.22	H33_56
33	BIG WEST OF CA, LLC	8	CRUDE UNIT #10 INCLUDING 209 MMBTU/HR GAS FIRED HEATER 10-H1 WITH WATER SPRAY NOZZLES FOR FLUE GAS COOLING AND SELECTIVE CATALYTIC REDUCTION (SCR), 65 MMBTU/HR GAS FIRED HEATER 10-H2, CRUDE TOWER 10-V1, DIESEL/AGO STRIPPER 10-V2A/B, DESALTER AND MISC. HEA	111.40	40,637	311.874	3917.500	311.874	3917.500	29.3	Assumed stack height based on professional judgement (considering size and type of operation).	0.70	0.69	209	MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 209 MMBtu/hr NG Process Heaters_Dryers	4.64	20.00	366.33	10.00	1.22	H33_8
33	BIG WEST OF CA, LLC	9	VACUUM UNIT #11 INCLUDING NATURAL GAS/REFINERY GAS FIRED VACUUM CHARGE HEATERS 11H1 AND 11H2 (142.6 MMBTU/HR TOTAL), VACUUM TOWER, FOUR STAGE VACUUM SYSTEM WITH GAS AMINE CONTACTOR AND MISC. PUMPS, PIPING, AND VESSELS - AREA 1	123.20	44,970	311.874	3917.500	311.874	3917.500	29.3	Assumed stack height based on professional judgement (considering size and type of operation).	0.77	0.77	142.6	MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 142.6 MMBtu/hr NG Process Heaters_Dryers	5.13	20.00	366.33	10.00	1.22	H33_9
34	BIG WEST OF CA, LLC	1	CRUDE UNIT INCLUDING DESALTERS, 96 MMBTU/HR REFINERY/NATURAL GAS FIRED CRUDE HEATER H-100 EQUIPPED WITH SELECTIVE CATALYTIC REDUCTION (SCR), LOW NOX BURNERS, NOX, CO, AND O2 CEM, FRACTIONING TOWER (V-101), STRIPPER (V-103), AND MISC PUMPS, PIPING, & HEAT	82.90	25,229	313.610	3918.585	313.610	3918.585	31.2	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.49	0.40	96	MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 96 MMBtu/hr NG Process Heaters_Dryers	3.45	20.00	366.33	10.00	1.22	H34_1
34	BIG WEST OF CA, LLC	2	VACUUM UNIT INCLUDING 38.3 MMBTU/HR REFINERY GAS-FIRED HEATER H-200 WITH 10 JOHN ZINK COOLSTAR LOW NOX BURNERS, THERMAL DENOX SYSTEM, DISTILLATION TOWER, 3 STEAM INJECTORS, EJECTOR DISCHARGE DRUM (V-201), AND MISC. PUMPS, PIPING, HEAT EXCHANGERS, AND VESS	165.50	12,078	313.610	3918.585	313.610	3918.585	31.2	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.97	0.19	38.3	MMBtu/hr	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 38.3 MMBtu/hr NG Process Heaters_Dryers	6.90	20.00	366.33	10.00	1.22	H34_2
34	BIG WEST OF CA, LLC	3	DELAYED COKING OPERATION INCLUDING DISTILLATION TOWER, TWO 35 MMBTU/HR GAS FIRED HEATERS WITH LOW-NOX BURNERS, QUENCH SYSTEM, COKE DRUMS, KNOCKOUT DRUM, COKE DRUM SUMP, STRIPPER TOWERS, COMPRESSORS, MISC. PUMPS, PIPING, & VESSELS, AND UTILIZING HTRS H-100	302.40	22,075	313.610	3918.585	313.610	3918.585	31.2	Assumed stack parameters based on professional judgement (considering size and type of operation).	1.77	0.35	35	MMBtu/hr (TWO)	NG	BigWest	Process Heaters_Dryers	0.32	BigWest 35 MMBtu/hr (TWO) NG Process Heaters_Dryers	12.60	20.00	366.33	10.00	1.22	H34_3
3984	BOWMAN ASPHALT INC	2	6000 TON PER DAY DUAL DRUM ASPHALTIC CONCRETE (A.C.) MANUFACTURING OPERATION WITH HAUCK ECO-STAR II MODEL 150 NATURAL GAS FIRED, STAGED FUEL BURNER,FABRIC COLLECTOR SERVING DRYER DRUM, MIXER DRUM, FINISHED A.C. CONVEYORS AND FINISHED A.C. SILOS	156.00	15,456	313.232	3918.362	313.232	3918.362	30.8	Assumed stack parameters based on professional judgement (considering size and type of operation). From the SJVAPCD, used the default in-stack NO2/NOx ratio for a "Boiler", an external combustion source with a slightly higher recommended ratio (10%) than that suggested for a dryer (6.88%) (this value appeared to be associated with a very specific dryer type (milk-tower dryer).	0.93	0.25		MMBtu/hr	NG	BowmanAsphalt	Process Heaters_Dryers	0.1	BowmanAsphalt MMBtu/hr NG Process Heaters_Dryers	6.50	10.00	310.78	10.00	0.46	H3984_2
40	CENTRAL RESOURCES INC	3	GAS PLANT FLARE, INCLUDING 10 FT. LONG MCGILL ENVIRONMENTAL SYSTEMS, INC. SMS-12-II FLARE TIP WITH CENTER STEAM INJECTION NOZZLE, 20 BHP, 8000 CFM AIR BLOWER, TWO PILOT ASSEMBLIES, AND SELF SUPPORTED FLARE STRUCTURE WITH BASE SECTION LIQUID SEAL	449.30	3,744	292.000	3903.497	292.000	3903.497	12.4	Emissions from this Central Resources Inc. (ID 40) flare was modeled instead of the 3 IC engine-driven compressors below as they are not permitted to run concurrently with non-emergency operation of the emergency flare (per 2008 Title V permit language provided by SJVAPCD). Also a test run showed that the contribution of the flare was larger than that of the three (3) IC engines. 720319.pdf	6.59	0.15		MMBtu/hr	NG	CentralRes	Flare	0.1	CentralRes MMBtu/hr NG Flare	18.72	17.57	1273.00	20.00	0.45	F40_3

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
723	CHALK CLIFF LIMITED	1	49 MW G.T.E. COGENERATION UNIT WITH STEAM INJECTION AND SELECTIVE CATALYTIC REDUCTION SYSTEM	190.80	69,642	281.720	3886.497	281.720	3886.497	25.7	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run	1.35	1.35	49	MW	NG	ChalkCliffLtd	Turbine-Large	0.17	ChalkCliffLtd 49 MW NG Turbine-Large	7.95	15.24	450.78	13.03	3.42	C723_1
1129	CHEVRON U S A INC	47	3.5 MW GAS TURBINE ENGINE COGENERATION UNIT #1 - MCKITTRICK	182.40	66,576	257.400	3910.890	257.400	3910.890	25.7	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	1.29	1.29	3.5	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 3.5 MW NG Turbine-Small	7.60	13.00	710.22	6.15	1.57	C1129_47
1129	CHEVRON U S A INC	48	3.5 MW GAS TURBINE ENGINE COGENERATION UNIT #2 - MCKITTRICK	182.40	66,576	257.400	3910.890	257.400	3910.890	25.7	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	1.29	1.29	3.5	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 3.5 MW NG Turbine-Small	7.60	13.00	710.22	6.15	1.57	C1129_48
1129	CHEVRON U S A INC	49	3.5 MW GAS TURBINE ENGINE COGENERATION UNIT #3 - MCKITTRICK	182.40	66,576	257.400	3910.890	257.400	3910.890	25.7	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	1.29	1.29	3.5	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 3.5 MW NG Turbine-Small	7.60	13.00	710.22	6.15	1.57	C1129_49
1129	CHEVRON U S A INC	53	3.5 MW COMBINED CYCLE GAS TURBINE TOPPING CYCLE COGENERATION NORTH MIDWAY UNIT #7	153.00	55,845	257.400	3910.890	257.400	3910.890	25.7	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	1.08	1.08	3.5	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 3.5 MW NG Turbine-Small	6.38	13.00	710.22	6.15	1.57	C1129_53
1129	CHEVRON U S A INC	54	3.5 MW COMBINED CYCLE GAS TURBINE TOPPING CYCLE COGENERATION NORTH MIDWAY UNIT #8	153.00	55,845	257.400	3910.890	257.400	3910.890	25.7	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions), except temp from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	1.08	1.08	3.5	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 3.5 MW NG Turbine-Small	6.38	13.00	710.22	6.15	1.57	C1129_54
3317	CHEVRON U S A INC	1	1200 HP SUPERIOR MODEL 2406 G NATURAL GAS-FIRED LEAN-BURN IC ENGINE DRIVING A GAS COMPRESSOR SERVING NATURAL GAS DISTRIBUTION AND SALES PIPELINE	50.00	18,257	326.764	3907.357	326.764	3907.357	43.9	Used same source parameters as obtained for 1,000 hp NG-fired NG compressors at Oxy.	0.21	0.21	1200	HP	NG	Chevron	IC Engine_Comp	0.6	Chevron 1200 HP NG IC Engine_Comp	2.08	6.40	691.33	9.66	0.51	CO3317_1
3317	CHEVRON U S A INC	2	1200 HP SUPERIOR MODEL 2406 G NATURAL GAS-FIRED LEAN-BURN IC ENGINE DRIVING A GAS COMPRESSOR SERVING NATURAL GAS DISTRIBUTION AND SALES PIPELINE	50.00	18,257	326.764	3907.357	326.764	3907.357	43.9	Used same source parameters as obtained for 1,000 hp NG-fired NG compressors at Oxy.	0.21	0.21	1200	HP	NG	Chevron	IC Engine_Comp	0.6	Chevron 1200 HP NG IC Engine_Comp	2.08	6.40	691.33	9.66	0.51	CO3317_2
1127	CHEVRON USA INC	22	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (CUSA ID #34-3, DIS #43006-74) WITH A NORTH AMERICAN MODEL GLE LOW NOX BURNER AND FLUE GAS RECIRCULATION (FGR) SYSTEM	54.00	19,710	322.400	3922.699	322.400	3922.699	40.7	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.24	0.24	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1127_22
1127	CHEVRON USA INC	29	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (CUSA ID #44-9, DIS #43007-75) WITH FLUE GAS RECIRCULATION AND WITH A NORTH AMERICAN MODEL GLE LOW NOX BURNER	54.00	19,710	322.400	3922.699	322.400	3922.699	40.7	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.24	0.24	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1127_29
1127	CHEVRON USA INC	30	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (CUSA ID #45-9, DIS #43008-75) WITH FLUE GAS RECIRCULATION AND WITH A NORTH AMERICAN MODEL GLE LOW NOX BURNER	54.00	19,710	322.400	3922.699	322.400	3922.699	40.7	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.24	0.24	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1127_30
1127	CHEVRON USA INC	31	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (CUSA ID #46-9, DIS #43009-75) WITH FLUE GAS RECIRCULATION AND WITH A NORTH AMERICAN MODEL GLE MAGNA FLAME LOW NOX BURNER	54.00	19,710	322.400	3922.699	322.400	3922.699	40.7	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.24	0.24	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1127_31

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1127	CHEVRON USA INC	34	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER AND FLUE GAS RECIRCULATION (CUSA ID# 49-5, DIS# 43003-76)	54.00	9,855	322.400	3922.699	322.400	3922.699	40.7	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.24	0.12	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1127_34
1127	CHEVRON USA INC	35	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER AND FLUE GAS RECIRCULATION (CUSA ID# 50-5, DIS# 43005-76)	54.00	9,855	322.400	3922.699	322.400	3922.699	40.7	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.24	0.12	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1127_35
1127	CHEVRON USA INC	36	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (CUSA ID #51-5, DIS #43004-76) WITH LOW PRESSURE FUEL INDUCED RECIRCULATION AND A NORTH AMERICAN MODEL GLE 4231 LOW NOX BURNER WITH FLUE GAS RECIRCULATION	54.00	19,710	322.400	3922.699	322.400	3922.699	40.7	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.24	0.24	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1127_36
1127	CHEVRON USA INC	70	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (CUSA ID #80-4, DIS #43010-82) WITH A FLUE GAS RECIRCULATION (FGR) SYSTEM AND A NORTH AMERICAN MODEL GLE LOW NOX BURNER	54.00	19,710	322.400	3922.699	322.400	3922.699	40.7	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.24	0.24	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1127_70
1128	CHEVRON USA INC	16	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MODEL GLE 4231 LOW NOX BURNER AND FGR (#50-2 DIS #43003-81)	54.00	19,710	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_16
1128	CHEVRON USA INC	18	62.5 MMBTU/HR NATURAL/VAPOR RECOVERY GAS FIRED STEAM GENERATOR #50-4-2F WITH SO2 SCRUBBER, NORTH AMERICAN GLE MAGNA-FLAME ULTRA-LOW NOX BURNER AND FGR - TAFT (GROUP II)	54.00	9,855	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.11	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_18
1128	CHEVRON USA INC	19	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (#50-5 DIS #43006-81) WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH FLUE GAS RECIRCULATION (FGR)	54.00	19,710	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_19
1128	CHEVRON USA INC	21	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR (CUSA ID# 90, DIS# 43010-80) WITH A NORTH AMERICAN GLE LOW-NOX BURNER AND FLUE GAS RECIRCULATION APPROVED TO OPERATE AT VARIOUS SPECIFIED LOCATIONS	54.00	9,965	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.11	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_21
1128	CHEVRON USA INC	25	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (CUSA ID# 62, DIS# 43002-79) WITH FLUE GAS RECIRCULATION APPROVED TO OPERATE AT VARIOUS SPECIFIED LOCATIONS	54.00	19,710	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_25
1128	CHEVRON USA INC	26	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (CUSA ID# 63, DIS# 43003-79) WITH FLUE GAS RECIRCULATION APPROVED TO OPERATE AT VARIOUS SPECIFIED LOCATIONS	54.00	19,710	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_26
1128	CHEVRON USA INC	28	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR #52 DIS# 43014-78 WITH FGR (APPROVED FOR VARIOUS SPECIFIED LOCATIONS)	54.00	19,710	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_28
1128	CHEVRON USA INC	29	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (CUSA ID# 55, DIS# 41752-06) WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER, SHARED SO2 SCRUBBER WITH S-1128-30, -31, -32, -33, AND -34 (CYMRIC), AND BRINKS MIST ELIMINATOR SYS	54.00	7,344	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.08	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_29

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1128	CHEVRON USA INC	30	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (CUSA ID# 56, DIS # 41753-06) WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER, EXHAUST VENTED TO SHARED SO2 SCRUBBER LISTED ON S-1128-29 (CYMRIC), AND BRINKS MIST ELIMINATOR SYS	54.00	7,344	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.08	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_30
1128	CHEVRON USA INC	31	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (CUSA ID# 57, DIS# 41763-06) WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER WITH EXHAUST VENTED TO SHARED SO2 SCRUBBER LISTED ON S-1128-29 (CYMRIC) AND BRINKS MIST ELIMINATOR S	54.00	7,344	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.08	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_31
1128	CHEVRON USA INC	32	ONE 62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (CUSA ID# 58, DIS# 41751-06) WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER, WITH EXHAUST VENTED TO SHARED SO2 SCRUBBER LISTED ON S-1128-29 (CYMRIC) AND BRINKS MIST ELIMINA	54.00	7,344	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.08	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_32
1128	CHEVRON USA INC	33	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (CUSA ID# 59, DIS# 41758-06) WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER, WITH EXHAUST VENTED TO SHARED SO2 SCRUBBER LISTED ON S-1128-29 (CYMRIC), AND BRINKS MIST ELIMINATOR	54.00	7,344	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.08	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_33
1128	CHEVRON USA INC	34	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (CUSA ID# 60, DIS# 41759-06) WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER, EXHAUST VENTED TO SHARED SO2 SCRUBBER LISTED ON S-1128-29 (CYMRIC), AND BRINKS MIST ELIMINATOR SYST	54.00	7,344	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.08	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_34
1128	CHEVRON USA INC	36	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MODEL MAGNA-FLAME GLE ULTRA-LOW NOX BURNER AND WITH SO2 SCRUBBER AND FLUE GAS RECIRCULATION (CUSA ID #50-3-26C)	54.00	19,710	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_36
1128	CHEVRON USA INC	38	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH FGR (#94)	54.00	9,965	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.11	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_38
1128	CHEVRON USA INC	48	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (CUSA ID# 50-4-26C) EQUIPPED WITH A NORTH AMERICAN MAGNAFLAME GLE ULTRA-LOW NOX BURNER WITH SO2 SCRUBBER AND FLUE GAS RECIRCULATION	54.00	9,855	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.11	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_48
1128	CHEVRON USA INC	57	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MODEL GLE 4231 LOW NOX BURNER AND FGR (#50-6 DIS #43012-81)	54.00	19,710	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_57
1128	CHEVRON USA INC	58	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR #50-7 DIS# 43013-81 WITH FGR	54.00	19,720	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_58
1128	CHEVRON USA INC	75	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR (CUSA ID# 91, DIS# 43001-85) WITH NORTH AMERICAN MAGNA FLAME GLE LOW-NOX BURNER AND FLUE GAS RECIRCULATION APPROVED TO OPERATE AT VARIOUS SPECIFIED LOCATIONS	54.00	19,710	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_75
1128	CHEVRON USA INC	77	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR (CUSA ID# 92, DIS# 37425-1) WITH A NORTH AMERICAN MODEL MAGNA FLAME GLE-4231 LOW NOX BURNER AND A WITH FLUE GAS RECIRCULATION, APPROVED TO OPERATE AT VARIOUS SPECIFIED LOCATIONS	54.00	19,710	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.22	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128_77

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1128	CHEVRON USA INC	159	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH FGR (CUSA ID# 18-A)	54.00	9,965	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.11	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128A59
1128	CHEVRON USA INC	941	62.5 MMBTU/HR NATURAL GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA LOW NOX BURNER WITH FGR	54.00	9,965	253.200	3944.289	253.200	3944.289	43.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.22	0.11	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1128I41
1131	CHEVRON USA INC	62	62.5 MMBTU/HR NATURAL GAS FIRED C.E. NATCO STEAM GENERATOR (HSG# 60-38; DIS# 20630-79) WITH FLUE GAS RECIRCULATION, NORTH AMERICAN MODEL GLE LOW-NOX BURNER, AND NORTH AMERICAN OPTIMIZER	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_62
1131	CHEVRON USA INC	63	62.5 MMBTU/HR NATURAL GAS-FIRED C.E. NATCO STEAM GENERATOR (HSG#60-39, DIS#20631-79) WITH NORTH AMERICAN GLE LOW-NOX BURNER, FLUE GAS RECIRCULATION (SAN JOAQUIN LOWER)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_63
1131	CHEVRON USA INC	64	62.5 MMBTU/HR NATURAL GAS-FIRED C.E. NATCO STEAM GENERATOR (HSG# 60-40; DIS# 20632-79) WITH FLUE GAS RECIRCULATION, NORTH AMERICAN GLE LOW-NOX BURNER AND NORTH AMERICAN OPTIMIZER.	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_64
1131	CHEVRON USA INC	66	62.5 MMBTU/HR NATURAL GAS-FIRED C.E. NATCO STEAM GENERATOR (HSG# 60-42; DIS# 20634-79) WITH FLUE GAS RECIRCULATION, NORTH AMERICAN GLE LOW-NOX BURNER AND NORTH AMERICAN OPTIMIZER. (SAN JOAQUIN LOWER)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_66
1131	CHEVRON USA INC	67	62.5 MMBTU/HR C.E. NATCO NATURAL GAS-FIRED STEAM GENERATOR (HSG# 60-43; DIS# 20635-79) WITH FLUE GAS RECIRCULATION AND A NORTH AMERICAN GLE LOW-NOX BURNER (SAN JOAQUIN LOWER)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_67
1131	CHEVRON USA INC	68	62.5 MMBTU/HR C.E. NATCO NATURAL GAS-FIRED STEAM GENERATOR (HSG# 60-44; DIS# 20636-79) WITH FLUE GAS RECIRCULATION AND A NORTH AMERICAN GLE LOW-NOX BURNER (SAN JOAQUIN LOWER)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_68
1131	CHEVRON USA INC	69	62.5 MMBTU/HR NATURAL GAS-FIRED C.E. NATCO STEAM GENERATOR (HSG# 60-45; DIS# 20637-79) WITH FLUE GAS RECIRCULATION, NORTH AMERICAN GLE LOW-NOX BURNER AND NORTH AMERICAN OPTIMIZER. (SAN JOAQUIN LOWER)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_69
1131	CHEVRON USA INC	70	62.5 MMBTU/HR NATURAL GAS-FIRED C.E. NATCO STEAM GENERATOR (HSG# 60-46; DIS# 20638-79) WITH A NORTH AMERICAN MAGNA FLAME GLE LOW-NOX BURNER AND FLUE GAS RECIRCULATION (SAN JOAQUIN LOWER)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_70
1131	CHEVRON USA INC	73	62.5 MMBTU/HR NATURAL GAS-FIRED C.E. NATCO STEAM GENERATOR (HSG# 60-49; DIS# 20641-79) WITH A NORTH AMERICAN MAGNA FLAME GLE LOW-NOX BURNER AND FLUE GAS RECIRCULATION (SAN JOAQUIN LOWER)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_73
1131	CHEVRON USA INC	78	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED C.E. NATCO STEAM GENERATOR (HSG# 60-69; DIS# 20610-79) WITH A NORTH AMERICAN MAGNA FLAME GLE LOW-NOX BURNER AND FLUE GAS RECIRCULATION (CANFIELD LEASE)	54.00	9,855	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.13	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_78

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1131	CHEVRON USA INC	82	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS-FIRED C.E. NATCO STEAM GENERATOR (HSG# 60-88; DIS# 20643-79) WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER, A FLUE GAS RECIRCULATION FGR SYSTEM AND NORTH AMERICAN OPTIMIZER - SJ LOWER	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_82
1131	CHEVRON USA INC	95	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS/GAS FIRED STRUTHERS STEAM GENERATOR (HSG# 70-31; DIS# 20642-79) WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER, FLUE GAS RECIRCULATION (FGR) SYSTEM AND NORTH AMERICAN OPTIMIZER - SJ LOWER	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_95
1131	CHEVRON USA INC	98	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (HSG# 70-44; DIS# 20608-82) WITH A NORTH AMERICAN MODEL #GLE-4231 LOW NOX BURNER AND FLUE GAS RECIRCULATION	54.00	9,855	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.13	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_98
1131	CHEVRON USA INC	99	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR (HSG# 70-45; DIS# 20609-82) WITH A NORTH AMERICAN MODEL #GLE-4231 LOW NOX BURNER AND FLUE GAS RECIRCULATION	54.00	9,855	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.13	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131_99
1131	CHEVRON USA INC	859	62.5 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (HSG# 50-51; DIS# 19161- 75) WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME, LOW NOX BURNER, FLUE GAS RECIRCULATION (FGR) SYSTEM AND NORTH AMERICAN OPTIMIZER (SAN JOAQUIN LOWER)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131H59
1131	CHEVRON USA INC	879	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN GLE LOW-NOX BURNER WITH FGR AND AN O2 CONTROLLER (#70, CENTRAL PLANT)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131H79
1131	CHEVRON USA INC	881	62.5 MMBTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN GLE LOW-NOX BURNER WITH FLUE GAS RECIRCULATION (FGR) AND AN O2 CONTROLLER (CENTRAL PLANT)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131H81
1131	CHEVRON USA INC	883	62.5 MM BTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS FIRED STRUTHERS STEAM GENERATOR (#143) WITH FGR AND O2 CONTROLLER (CENTRAL PLANT)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MM	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MM NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131H83
1131	CHEVRON USA INC	884	62.5 MM BTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STRUTHERS STEAM GENERATOR #144 EQUIPPED WITH NORTH AMERICAN MAGNA-FLAME GLE ULTRA LOW NOX BURNER AND FLUE GAS RECIRCULATION. (CENTRAL PLANT)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MM	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MM NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131H84
1131	CHEVRON USA INC	908	62.5 MM BTU/HR STRUTHERS NATURAL GAS/VAPOR RECOVERY GAS FIRED STRUTHERS STEAM GENERATOR (#71) WITH A NORTH AMERICAN GLE LOW-NOX BURNER, A FLUE GAS RECIRCULATION SYSTEM (FGR), AND O2 CONTROLLER	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MM	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MM NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131I08
1131	CHEVRON USA INC	912	62.5 MMBTU/HR NATURAL GAS FIRED STEAM GENERATOR WITH A NORTH AMERICAN GLE LOW-NOX BURNER AND A FLUE GAS RECIRCULATION (FGR) SYSTEM (RASMUSSEN LEASE)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131I12
1131	CHEVRON USA INC	987	62.5 MMBTU/HR THERMOTICS GAS/CASING GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER, OXYGEN CONTROLLER/ANALYZER AND FLUE GAS RECIRCULATION (FGR) SYSTEM (R-3, DIS# 27474-81)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131I87

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1131	CHEVRON USA INC	997	62.5 MMBTU/HR THERMOTICS NATURAL GAS/CASING GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME BURNER WITH FLUE GAS RECIRCULATION (FGR) AND AN OXYGEN CONTROLLER/ANALYZER (ANGUS 2, DIS# 4509-81)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131I97
1131	CHEVRON USA INC	999	62.5 MMBTU/HR C.E. NATCO GAS/CASING GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MODEL GLE MAGNA-FLAME LOW NOX BURNER, OXYGEN CONTROLLER/ANALYZER AND FLUE GAS RECIRCULATION (FGR) SYSTEM (RAMBLER, R-7, DIS# 12466-82)	54.00	19,710	319.000	3922.798	319.000	3922.798	37.4	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.26	0.26	62.5	MMBTU/HR	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1131I99
1141	CHEVRON USA INC	19	62.5 MMBTU/HR STRUTHERS NATURAL GAS-FIRED STEAM GENERATOR #38 (SN 80-37391-2, NB 983, DIS 20629-81) WITH A NORTH AMERICAN BURNER AND A THERMOX O2 CONTROLLER	54.00	19,710	262.500	3900.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.44	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141_19
1141	CHEVRON USA INC	26	62.5 MMBTU/HR STRUTHERS THERMOFLOOD NATURAL GAS/TEOR GAS/TVC VAPORS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MODEL GLE 4231 ULTRA-LOW NOX BURNER, FGR, A THERMOX O2 CONTROLLER, VAPOR PIPING FROM TEOR SYSTEM, VAPOR PIPING FROM TVC SYSTEMS, AND A SULFA SC	54.00	9,965	263.000	3900.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141_26
1141	CHEVRON USA INC	31	62.5 MMBTU/HR NATURAL GAS/TEOR/TVC GAS FIRED CE NATCO STEAM GENERATOR #59 (DIS# 20639-81, NATIONAL BOARD #1352), WITH NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER, O2 CONTROLLER AND FGR PERMITTED TO OPERATE WITH EITHER AN AIR-FUEL MIXING ROD OR A	54.00	9,855	263.500	3900.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141_31
1141	CHEVRON USA INC	38	62.5 MMBTU/HR C. E. NATCO NATURAL GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH FGR AND AN O2 CONTROLLER (#79, SN T-6155901-11, NB 9815, DIS 20664-77)	54.00	9,965	264.000	3900.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141_38
1141	CHEVRON USA INC	43	62.5 MMBTU/HR NATURAL GAS/TEOR GAS FIRED STRUTHERS STEAM GENERATOR (SG #87, N.B. 998) WITH NORTH AMERICAN GLE ULTRA-LOW NOX BURNER, O2 CONTROLLER, AND FLUE GAS RECIRCULATION (FGR)	54.00	9,855	264.500	3900.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141_43
1141	CHEVRON USA INC	44	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS-FIRED STRUTHERS STEAM GENERATOR #106 (SN81-37398-9, NB 661, DIS 12462) WITH FLUE GAS RECIRCULATION, NORTH AMERICAN MAGNA-FLAME GLE LOW NOX BURNER, O2 CONTROLLER AND VAPOR PIPING FROM TEOR SYSTEMS AND STATION 2-22 TANKS	54.00	9,855	265.000	3900.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141_44
1141	CHEVRON USA INC	45	62.5 MMBTU/HR NATURAL GAS/TEOR GAS/TVC GAS FIRED STRUTHERS STEAM GENERATOR #93 (SN 81-37398-10, NB 1003, DIS 12463-82) WITH FLUE GAS RECIRCULATION, NORTH AMERICAN MAGNA-FLAME GLE LOW NOX BURNER, O2 CONTROLLER, AND VAPOR PIPING FROM TEOR AND TVC SYSTEMS	54.00	9,855	262.500	3900.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141_45
1141	CHEVRON USA INC	51	62.5 MMBTU/HR C. E. NATCO NATURAL GAS/TEOR GAS-FIRED STEAM GENERATOR #99 (SN T-6718101-08, NB 130, DIS 20640-79) WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH FLUE GAS RECIRCULATION (FGR) AND AN O2 ANALYZER/CONTROLLER	54.00	9,855	263.000	3900.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141_51
1141	CHEVRON USA INC	67	62.5 MMBTU/HR C.E. NATCO NATURAL GAS/TEOR GAS-FIRED STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH FGR AND AN O2 CONTROLLER (#121, SN T-6718101-04, NB 108, DIS 20639-79)	54.00	9,965	263.500	3900.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141_67
1141	CHEVRON USA INC	368	62.5 MMBTU/HR NATURAL GAS-FIRED SMITH MOON STEEL STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH FGR AND AN OXYGEN CONTROLLER	54.00	9,965	264.000	3900.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141C68

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1141	CHEVRON USA INC	369	62.5 MMBTU/HR NATURAL GAS FIRED SMITH MOON STEEL STEAM GENERATOR #131 (NB 890) WITH O2 CONTROLLER, NORTH AMERICAN BURNER, AND FLUE GAS RECIRCULATION	54.00	19,710	264.500	3900.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.44	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141C69
1141	CHEVRON USA INC	370	62.5 MMBTU/HR NATURAL GAS FIRED SMITH MOON STEEL STEAM GENERATOR #132 (NB 888) WITH O2 CONTROLLER, FLUE GAS RECIRCULATION, AND NORTH AMERICAN MAGNA FLAME GLE BURNER	54.00	9,855	265.000	3900.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141C70
1141	CHEVRON USA INC	371	62.5 MMBTU/HR SMITH MOON STEEL NATURAL GAS-FIRED STEAM GENERATOR #133 (DIS# 19962-71) WITH A NORTH AMERICAN BURNER WITH FLUE GAS RECIRCULATION (FGR) AND AN O2 CONTROLLER	54.00	19,710	262.500	3901.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.44	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141C71
1141	CHEVRON USA INC	372	62.5 MMBTU/HR NATURAL GAS/TEOR GAS FIRED C. E. NATCO STEAM GENERATOR #79 (SN T-7585901-07, NB 1220, DIS 20633-81) WITH A NORTH AMERICAN MODEL 4231-625-GLE LOW NOX BURNER, FLUE GAS RECIRCULATION, AND O2 CONTROLLER	54.00	9,965	263.000	3901.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141C72
1141	CHEVRON USA INC	373	62.5 MMBTU/HR SMITH MOON STEEL NATURAL GAS-FIRED STEAM GENERATOR (DIS# 19452-71) WITH A NORTH AMERICAN MODEL #6141 LOW NOX BURNER WITH FLUE GAS RECIRCULATION (FGR) AND AN OXYGEN CONTROLLER - NMSP-135 (NATIONAL BOARD NUMBER - 551, COMPANY LOCATION NUMBER -	54.00	9,855	263.500	3901.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141C73
1141	CHEVRON USA INC	374	62.5 MMBTU/HR NATURAL GAS-FIRED SMITH MOON STEEL STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH FGR AND AN OXYGEN CONTROLLER (#4, SN 74-37127-1, NB 668)	54.00	9,965	264.000	3901.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141C74
1141	CHEVRON USA INC	380	62.5 MMBTU/HR NATURAL GAS-FIRED C.E. NATCO STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH FGR AND AN OXYGEN CONTROLLER (#141, NB 101, DIS# 20630-79)	54.00	9,965	264.500	3901.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141C80
1141	CHEVRON USA INC	402	62.5 MMBTU/HR SMITH MOON STEEL NATURAL GAS FIRED STEAM GENERATOR HSG #192 (SN 79-37317-3, NB 901, DIS 20634-79) WITH NORTH AMERICAN BURNER - (INDIAN & COLONIAL LEASE)	54.00	19,710	265.000	3901.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.44	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141D02
1141	CHEVRON USA INC	516	62.5 MMBTU/HR NATURAL GAS/TEOR GAS FIRED SMITH MOON STEEL STEAM GENERATOR (N.B. #827 A) WITH NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER	54.00	9,855	262.500	3901.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E16
1141	CHEVRON USA INC	549	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS-FIRED STRUTHERS STEEL STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA LOW-NOX BURNER, WITH AN O2 ANALYZER/CONTROLLER AND FLUE GAS RECIRCULATION (FGR) SYSTEM WITH VARIABLE SPEED INTAKE AIR BLOWER, ORIFICE PLAT	54.00	9,965	263.000	3901.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E49
1141	CHEVRON USA INC	550	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS-FIRED SMITH MOON STEEL STEAM GENERATOR WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH AN O2 ANALYZER/CONTROLLER AND FGR WITH VARIABLE SPEED INTAKE AIR BLOWER, ORIFICE PLATE(S), AND ELECTRONIC CONTROLS (N	54.00	9,965	263.500	3901.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E50
1141	CHEVRON USA INC	551	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS FIRED CE NATCO STEAM GENERATOR (NATIONAL BOARD #2369) WITH A NORTH AMERICAN MODEL MAGNA-FLAME GLE ULTRA LOW NOX BURNER, AN O2 CONTROLLER, AND A FLUE GAS RECIRCULATION SYSTEM	54.00	9,855	264.000	3901.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E51

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1141	CHEVRON USA INC	552	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS FIRED CE NATCO STEAM GENERATOR (NATIONAL BOARD #192) WITH NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER, O2 CONTROLLER, AND FGR	54.00	9,855	264.500	3901.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E52
1141	CHEVRON USA INC	553	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS FIRED SMITH MOON STEEL STEAM GENERATOR (NATIONAL BOARD #552) WITH NORTH AMERICAN BURNER, O2 ANALYZER/CONTROLLER, AND FGR WITH VARIABLE SPEED INTAKE AIR BLOWER, ORIFICE PLATE(S), AND ELECTRONIC CONTROLS	54.00	19,710	265.000	3901.500	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.44	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E53
1141	CHEVRON USA INC	554	62.5 MMBTU/HR NATURAL GAS FIRED SMITH MOON STEEL STEAM GENERATOR (NATIONAL BOARD #690) WITH A NORTH AMERICAN MODEL MAGNA-FLAME GLE ULTRA LOW NOX BURNER, AN O2 CONTROLLER, AND A FLUE GAS RECIRCULATION SYSTEM	54.00	9,855	262.500	3902.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E54
1141	CHEVRON USA INC	555	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS FIRED SMITH MOON STEEL STEAM GENERATOR (NATIONAL BOARD #7953) WITH NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER, O2 CONTROLLER, FGR AND EXHAUST GAS SOX SCRUBBER AND BRINKS MIST ELIMINATOR SHARED WITH S-1141-555, -	54.00	9,855	263.000	3902.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E55
1141	CHEVRON USA INC	556	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS-FIRED SMITH MOON STEEL STEAM GENERATOR (NATIONAL BOARD #653) WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA-LOW NOX BURNER WITH AN O2 ANALYZER/CONTROLLER, FGR (WITH VARIABLE SPEED INTAKE AIR BLOWER, ORIFICE PLATE(S), ELECTR	54.00	9,855	263.500	3902.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E56
1141	CHEVRON USA INC	557	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS-FIRED C.E. NATCO STEAM GENERATOR (NATIONAL BOARD #9333) WITH A NORTH AMERICAN MAGNA-FLAME GLE ULTRA LOW-NOX BURNER, O2 ANALYZER/CONTROLLER, FGR SYSTEM (WITH VARIABLE SPEED INTAKE AIR BLOWER, ORIFICE PLATE(S), ELECTRONIC	54.00	9,855	264.000	3902.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E57
1141	CHEVRON USA INC	558	62.5 MMBTU/HR NATURAL/TEOR/TVC GAS FIRED CE NATCO STEAM GENERATOR (NATIONAL BOARD #2398) WITH A NORTH AMERICAN MAGNA-FLAME MODEL GLE ULTRA LOW NOX BURNER, FGR AND O2 CONTROLLER	54.00	9,855	264.500	3902.000	263.800	3900.796	22.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.44	0.22	62.5	MMBtu/hr	NG	Chevron	Boiler/Steam Gen	0.1	Chevron 62.5 MMBtu/hr NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1141E58
1127	CHEVRON USA INC	148	22.3 MW NOMINAL RATING COMBINED CYCLE COGENERATION UNIT A, DIS# 47003-88, INCLUDING GAS-FIRED GE LM-2500-PE TURBINE WITH NOMINAL RATING INPUT OF 240 MMBTU/HR AND SCR FOR NOX CONTROL	133.90	48,874	322.400	3922.699	322.400	3922.699	40.7	Stack parameters assumed same as 38.7 MW Berry plant.	0.60	0.60	22.3	MW	NG	Chevron	Turbine-Large	0.17	Chevron 22.3 MW NG Turbine-Large	5.58	15.24	450.78	13.03	3.42	C1127A48
1127	CHEVRON USA INC	149	22.3 MW NOMINAL RATING COMBINED CYCLE COGENERATION UNIT B, DIS# 47004-88, INCLUDING GAS-FIRED GE LM-2500-PE TURBINE WITH NOMINAL RATING INPUT OF 240 MMBTU/HR AND SCR FOR NOX CONTROL	133.90	48,874	322.400	3922.699	322.400	3922.699	40.7	Stack parameters assumed same as 38.7 MW Berry plant.	0.60	0.60	22.3	MW	NG	Chevron	Turbine-Large	0.17	Chevron 22.3 MW NG Turbine-Large	5.58	15.24	450.78	13.03	3.42	C1127A49
1128	CHEVRON USA INC	366	2.7 MW COGEN FACILITY (CUSA ID# CG-1) INCLUDING: SOLAR CENTAUR 37.6 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 39 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	250.70	94,506	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.04	1.08	2.7	MW	NG	Small turbine	Turbine-Small	0.1032	Small turbine 2.7 MW NG Turbine-Small	10.45	13.00	367.44	6.15	1.57	C1128C66
1128	CHEVRON USA INC	367	2.7 MW COGEN FACILITY (CUSA ID# CG-2) INCLUDING: SOLAR CENTAUR 37.6 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 37 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	250.70	94,506	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.04	1.08	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	10.45	13.00	367.44	6.15	1.57	C1128C67
1128	CHEVRON USA INC	368	2.7 MW COGEN FACILITY (CUSA ID# CG-3) INCLUDING: SOLAR CENTAUR 37.6 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 37 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	250.70	94,506	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.04	1.08	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	10.45	13.00	367.44	6.15	1.57	C1128C68

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1128	CHEVRON USA INC	369	2.7 MW COGEN FACILITY (CUSA ID# CG-4) INCLUDING: SOLAR CENTAUR 37.6 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 37 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	250.70	94,506	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.04	1.08	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	10.45	13.00	367.44	6.15	1.57	C1128C69
1128	CHEVRON USA INC	370	2.7 MW COGEN FACILITY (CUSA ID# 36W CG-1) INCLUDING: SOLAR CENTAUR 37.6 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE WITH STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 39 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	278.00	101,543	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.16	1.16	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	11.58	13.00	367.44	6.15	1.57	C1128C70
1128	CHEVRON USA INC	371	2.7 MW COGEN FACILITY (CUSA ID# 36W CG-2) INCLUDING: SOLAR CENTAUR 37.6 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 39 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	278.00	101,543	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.16	1.16	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	11.58	13.00	367.44	6.15	1.57	C1128C71
1128	CHEVRON USA INC	372	2.7 MW COGEN FACILITY (CUSA ID# 36W CG-3) INCLUDING: SOLAR CENTAUR 37.6 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 37 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	278.20	101,543	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.16	1.16	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	11.59	13.00	367.44	6.15	1.57	C1128C72
1128	CHEVRON USA INC	373	2.7 MW COGEN FACILITY (CUSA ID# 36W CG-4) INCLUDING: SOLAR CENTAUR 37.6 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE WITH STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 37 MMBTU/HR (NOMINAL RATING) DUCT BURNER	278.20	101,543	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.16	1.16	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	11.59	13.00	367.44	6.15	1.57	C1128C73
1128	CHEVRON USA INC	374	2.7 MW COGEN FACILITY (CUSA ID# 31X CG-1) INCLUDING: SOLAR CENTAUR 40.9 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 37 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	278.20	101,543	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.16	1.16	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	11.59	13.00	367.44	6.15	1.57	C1128C74
1128	CHEVRON USA INC	375	2.7 MW COGEN FACILITY (CUSA ID# 31X CG-2) INCLUDING: SOLAR CENTAUR 40.9 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STURTHERS HEAT RECOVERY STEAM GENERATOR WITH 37 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	278.20	101,543	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.16	1.16	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	11.59	13.00	367.44	6.15	1.57	C1128C75
1128	CHEVRON USA INC	376	2.7 MW COGEN FACILITY (CUSA ID# 6Z CG-1) INCLUDING: SOLAR CENTAUR 40.9 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 37 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	278.20	101,543	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.16	1.16	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	11.59	13.00	367.44	6.15	1.57	C1128C76
1128	CHEVRON USA INC	377	2.7 MW COGEN FACILITY (CUSA ID# 6Z CG-2) INCLUDING: SOLAR CENTAUR 40.9 MMBTU/HR (NOMINAL RATING), WATER INJECTED, GAS TURBINE ENGINE AND STRUTHERS HEAT RECOVERY STEAM GENERATOR WITH 37 MMBTU/HR (NOMINAL RATING) COEN DUCT BURNER	278.20	101,543	253.200	3944.289	253.200	3944.289	43.9	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.16	1.16	2.7	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 2.7 MW NG Turbine-Small	11.59	13.00	367.44	6.15	1.57	C1128C77
1131	CHEVRON USA INC	970	COGENERATION UNIT #1 (NORTH UNIT) SOLAR CENTAUR TYPE H, 52.4 MMBTU/HR GAS FIRED TURBINE ENGINE, 3.725 MW, WITH WATER INJECTION AND STRUTHERS UNFIRED HEAT RECOVERY STEAM GENERATOR - LEASE FEE A	162.20	59,214	319.000	3922.798	319.000	3922.798	37.4	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	0.79	0.79	3.725	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 3.725 MW NG Turbine-Small	6.76	13.00	367.44	6.15	1.57	C1131I70
1131	CHEVRON USA INC	973	COGENERATION UNIT #1 (WEST) SOLAR CENTAUR TYPE H, 52.4 MM BTU/HR GAS FIRED TURBINE ENGINE, 3.725 MW, WITH WATER INJECTION AND STRUTHERS UNFIRED HEAT RECOVERY STEAM GENERATOR - FEE A	162.20	59,214	319.000	3922.798	319.000	3922.798	37.4	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	0.79	0.79	3.725	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 3.725 MW NG Turbine-Small	6.76	13.00	367.44	6.15	1.57	C1131I73
1131	CHEVRON USA INC	974	COGENERATION UNIT #2 (EAST): SOLAR CENTAUR TYPE H, 52.4 MMBTU/HR GAS FIRED TURBINE ENGINE, 3.725 MV, WITH WATER INJECTION AND STRUTHERS UNFIRED HEAT RECOVERY STEAM GENERATOR - LEASE FEE C	161.00	59,641	319.000	3922.798	319.000	3922.798	37.4	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	0.79	0.80	3.725	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 3.725 MW NG Turbine-Small	6.71	13.00	367.44	6.15	1.57	C1131I74

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1131	CHEVRON USA INC	1037	249.0 MMBTU/HR NOMINAL RATING, 20 MW NOMINAL RATING GENERAL ELECTRIC GAS-FIRED TURBINE ENGINE COGENERATION SYSTEM WITH SCR, AMMONIA STORAGE AND DISTRIBUTION SYSTEM, CO CATALYTIC CONVERTER AND CEM SYSTEM FOR NOX, CO AND O2	110.00	40,135	319.000	3922.798	319.000	3922.798	37.4	Stack parameters assumed same as 38.7 MW Berry plant, except temperature data from Solar Turbines data sheet for Centaur 40 2.5 MW turbine generator set	0.54	0.54	20	MW	NG	Chevron	Turbine-Large	0.17	Chevron 20 MW NG Turbine-Large	4.58	15.24	710.22	13.03	3.42	C1131J37
1131	CHEVRON USA INC	1038	58.2 MMBTU/HR, 4.0 MW ALLISON MODEL 501-KB5 GAS-FIRED TURBINE ENGINE COGENERATION SYSTEM WITH WATER INJECTION, HEAT RECOVERY STEAM GENERATOR, AND CEM SYSTEMS FOR NOX, CO, AND O2	180.20	65,768	319.000	3922.798	319.000	3922.798	37.4	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run, except temp assumed same as that used for Frito 6 MW cogen	0.88	0.88	58.2	MMBTU/HR,	NG	Chevron	Turbine-Small	0.1032	Chevron 58.2 MMBTU/HR, NG Turbine-Small	7.51	15.24	367.44	13.00	3.42	C1131J38
1131	CHEVRON USA INC	1039	58.2 MMBTU/HR, 4.0 MW ALLISON MODEL 501-KB5 GAS-FIRED TURBINE ENGINE COGENERATION SYSTEM WITH WATER INJECTION, HEAT RECOVERY STEAM GENERATOR, AND CEM SYSTEMS FOR NOX, CO, AND O2	180.20	65,768	319.000	3922.798	319.000	3922.798	37.4	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run, except temp assumed same as that used for Frito 6 MW cogen	0.88	0.88	58.2	MMBTU/HR,	NG	Chevron	Turbine-Small	0.1032	Chevron 58.2 MMBTU/HR, NG Turbine-Small	7.51	15.24	367.44	13.00	3.42	C1131J39
1131	CHEVRON USA INC	1079	COGENERATION UNIT #1 (FEE C LEASE - WEST UNIT) SOLAR CENTAUR 50-T5901S, 48.7 MMBTU/HR GAS FIRED DOE CERAMIC GTE, 4.1 MW, WITH LUBE OIL MIST ELIMINATOR, UNFIRED HEAT RECOVERY STEAM GENERATOR, AND CONTINUOUS MONITORING SYSTEM.	107.60	39,291	319.000	3922.798	319.000	3922.798	37.4	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	0.52	0.52	4.1	MW	NG	Chevron	Turbine-Small	0.1032	Chevron 4.1 MW NG Turbine-Small	4.48	13.00	367.44	6.15	1.57	C1131J79
1128	CHEVRON USA INC	116	TEOR OPERATION WELL VENT VR SYSTEM #CC-36W #1 SERVING 146 STEAM DRIVE WELLS AND 6 AUTOMATIC WELL TEST VESSELS W/ VAPOR PIPING TO SCRUBBED STEAM GENERATORS, DOGGR APPROVED DISPOSAL WELLS(S,) SULFEROX H2S REMOVAL PLANT, 0.34 MMBTU/HR KALDAIR FLARE (FLARE SH	479.50	2,767	253.200	3944.289	253.200	3944.289	43.9	Heat input rating borrowed from similar Chevron facility source F1141E13, as this one looks far too low. Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	2.00	0.03	167	MMBTU/HR	vapor	Chevron	Flare	0.1	Chevron 167 MMBTU/HR vapor Flare	19.98	23.90	1273.00	20.00	2.27	F1128A16
1141	CHEVRON USA INC	513	167 MM BTU/HR DUAL BLOWER AIR-ASSISTED EMERGENCY GROUND FLARE WITH KALDAIR AZDAIR PLA-12 FLARE TIP AND 9' DIA X 40' TALL FLAME ENCLOSURE SERVING TANK VAPOR RECOVERY EQUIPMENT LISTED ON S-1141-127-3 STATION 109.	400.30	3,400	263.800	3900.796	263.800	3900.796	22.4	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	3.26	0.08	167	MMBtu/hr	Vapor	Chevron	Flare	0.1	Chevron 167 MMBtu/hr Vapor Flare	16.68	23.90	1273.00	20.00	2.27	F1141E13
1141	CHEVRON USA INC	514	167 MMBTU/HR DUAL BLOWER AIR-ASSISTED EMERGENCY GROUND FLARE WITH KALDAIR AZDAIR PLA-12 FLARE TIP AND 9' DIA X 40' TALL FLAME ENCLOSURE SERVING TANK VAPOR RECOVERY EQUIPMENT LISTED ON S-1141-88-3 STATION 2-22, S-1141-479 THROUGH '-486, S-1141-487, S-1141-	400.30	3,400	263.800	3900.796	263.800	3900.796	22.4	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	3.26	0.08	167	MMBtu/hr	Vapor	Chevron	Flare	0.1	Chevron 167 MMBtu/hr Vapor Flare	16.68	23.90	1273.00	20.00	2.27	F1141E14
75	COVANTA DELANO INC	11	315 MMBTU/HR EPI FLUIDIZED BUBBLING BED, BIOMASS-FUELED BOILER (UNIT #2) WITH NH3, LIMESTONE, SAND AND SODIUM BICARBONATE (NAHCO3) INJECTION, WITH BOILER EXHAUST VENTED TO SIX COMPARTMENT FABRIC FILTER DUST COLLECTOR; AND FOUR 10 MMBTU/HR THERMAL SOLUTION	756.00	275,940	298.073	3954.980	298.073	3954.980	45.3	32 MW from http://www.covantaenergy.com/?sc_itemid={883CF53F-D0DA-44FA-B6D2-3C9DB0C4D623} Stack parameters obtained from similar facilty type (San Joaquin Solar project).	3.04	3.04	315	MMBTU/HR	biomass	CovDelanoInc	Fluidized bed-bio	0.5	CovDelanoInc 315 MMBTU/HR biomass Fluidized bed-bio	31.50	30.48	383.00	25.00	2.00	B75_11
75	COVANTA DELANO INC	6	400 MMBTU/HR (32 MW) EPI FLUIDIZED BED, BIOMASS-FUELED BOILER (UNIT #1) WITH NH3, LIMESTONE, SODIUM BICARBONATE, AND SAND INJECTION, WITH BOILER EXHAUST VENTED TO FABRIC FILTER; AND FOUR 10 MMBTU/HR PORTABLE NATURAL GAS-FIRED REFRACTORY CURING HEATERS	960.00	350,400	298.073	3954.980	298.073	3954.980	45.3	32 MW from http://www.covantaenergy.com/?sc_itemid={883CF53F-D0DA-44FA-B6D2-3C9DB0C4D623} Stack parameters obtained from similar facilty type (San Joaquin Solar project).	3.87	3.87	400	MMBTU/HR	biomass	CovDelanoInc	Fluidized bed-bio	0.5	CovDelanoInc 400 MMBTU/HR biomass Fluidized bed-bio	40.00	30.48	383.00	25.00	2.00	B75_6
724	DAI OILDALE INC	1	COGENERATION SYSTEM WITH GE LM2500PE 250 MMBTU/HR GAS-FIRED GAS TURBINE ENGINE, 22.1 MW GAS & 7 MW STEAM TURBINE ELECTRICAL GENERATORS, INLET AIR ABSORPTION CHILLER, WATER INJECTION, UNFIRED HEAT RECOVERY STEAM GENERATOR, & BABCOCK-HITACHI SCR SYSTEM	170.60	62,269	317.290	3923.801	317.290	3923.801	36.1	Stack parameters have same assumptions as those for 40 MW cogen at Berry Petro in prior run, except temp assumed same as 6 MW Frito Lay w HRSG plant in prior run.	0.86	0.86	22.1	MW	NG	DAIOildaleInc	Turbine-Large	0.17	DAIOildaleInc 22.1 MW NG Turbine-Large	7.11	15.24	367.44	13.03	3.42	C724_1
1119	DOUBLE C LIMITED	1	NOMINALLY RATED 25 MW GENERAL ELECTRIC LM-2500 NATURAL GAS FIRED GAS TURBINE ENGINE COGENERATION SYSTEM WITH STEAM INJECTION	97.00	35,390	314.421	3930.483	314.421	3930.483	36.3	Stack parameters assumed same as 38.7 MW Berry plant.	0.49	0.49	25	MW	NG	DblCLtd	Turbine-Large	0.17	DblCLtd 25 MW NG Turbine-Large	4.04	15.24	450.78	13.03	3.42	C1119_1
1119	DOUBLE C LIMITED	2	NOMINALLY RATED 25 MW GENERAL ELECTRIC LM-2500 NATURAL GAS FIRED GAS TURBINE ENGINE COGENERATION SYSTEM WITH STEAM INJECTION	97.00	35,390	314.421	3930.483	314.421	3930.483	36.3	Stack parameters assumed same as 38.7 MW Berry plant.	0.49	0.49	25	MW	NG	DblCLtd	Turbine-Large	0.17	DblCLtd 25 MW NG Turbine-Large	4.04	15.24	450.78	13.03	3.42	C1119_2

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
3523	ELK HILLS POWER LLC	1	GE FRAME 7 MODEL PG7241FA NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #1 WITH DRY LOW NOX COMBUSTORS, 250.5 MMBTU/HR NATURAL GAS FIRED DUCT BURNER, HEAT RECOVERY STEAM GENERATOR, SELECTIVE CATALYTIC REDUCTION, OXIDATION CATALY	752.00	167,511	0.275	3.907	275.598	3906.716	9.3	FDOC PTE condition AQ-13 and FDOC stack parameters and emission rate for startup hour, Elk Hills Power Plant GE Frame 7. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD)	14.76	9.01	250.5	MMBTU/hr	NG	Elk	Turbine-Large	0.17	Elk 250.5 MMBTU/hr NG Turbine-Large	38.00	36.60	345.00	12.50	5.49	ELK_STK1
3523	ELK HILLS POWER LLC	2	GE FRAME 7 MODEL PG7241FA NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #2 WITH DRY LOW NOX COMBUSTORS, 250.5 MMBTU/HR NATURAL GAS FIRED DUCT BURNER, HEAT RECOVERY STEAM GENERATOR, SELECTIVE CATALYTIC REDUCTION, OXIDATION CATALY	752.00	167,511	0.275	3.907	275.598	3906.716	9.3	FDOC PTE condition AQ-13 and FDOC stack parameters and emission rate for startup hour, Elk Hills Power Plant GE Frame 7. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD)	14.76	9.01	250.5	MMBTU/hr	NG	Elk	Turbine-Large	0.17	Elk 250.5 MMBTU/hr NG Turbine-Large	38.00	36.60	345.00	12.50	5.49	ELK_STK2
1328	EXXON MOBIL CORPORATION	1	62.5 MMBTU/HR GAS-FIRED STRUTHERS STEAM GENERATOR UNIT #64 WITH NORTH AMERICAN MAGNA FLAME GLE NOX BURNER, FGR AND O2 CONTROLLER (HILL LEASE)	54.00	8,578	250.400	3929.189	250.400	3929.189	36.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.27	0.12	62.5	MMBTU/HR	NG	ExxonMobil	Boiler/Steam Gen	0.1	ExxonMobil 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1328_1
1328	EXXON MOBIL CORPORATION	2	62.5 MMBTU/HR GAS-FIRED STRUTHERS STEAM GENERATOR UNIT #65 WITH NORTH AMERICAN MAGNA FLAME GLE NOX BURNER, FGR AND O2 CONTROLLER (HILL LEASE)	54.00	8,578	250.400	3929.189	250.400	3929.189	36.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.27	0.12	62.5	MMBTU/HR	NG	ExxonMobil	Boiler/Steam Gen	0.1	ExxonMobil 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1328_2
1328	EXXON MOBIL CORPORATION	3	62.5 MMBTU/HR NATURAL GAS/TEOR GAS-FIRED STRUTHERS STEAM GENERATOR UNIT #66 WITH NORTH AMERICAN MAGNA FLAME GLE NOX BURNER, FGR AND O2 CONTROLLER (HILL LEASE)	54.00	8,578	250.400	3929.189	250.400	3929.189	36.9	Obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.27	0.12	62.5	MMBTU/HR	NG	ExxonMobil	Boiler/Steam Gen	0.1	ExxonMobil 62.5 MMBTU/HR NG Boiler/Steam Gen	2.25	7.32	421.89	5.51	1.07	B1328_3
705	FARMERS COOP GIN INC	1	COTTON GIN #1 WITH WAGON UNLOADER, 16 CLEANERS, 6 DRYERS WITH 5 HEATERS, 4 SAW GIN STANDS, 8 LINT CLEANERS, BATTERY CONDENSER, 2 MMBTU/HR MOISTURIZER, MOTES SYSTEM, OVERFLOW SYSTEM, TRASH LINT EXTRACTOR, AND SEED COLLECTION SYSTEM	48.50	8,640	277.698	3919.952	277.698	3919.952	9.4	Assumed stack height based on professional judgement. ATC review of cyclones prior to exhaust, 767655.pdf, stack velocity. Assumed stack diameter based on professional judgement (considering size and type of operation). Appears to include both heaters and dryers, so opted for "Process Heater" label and higher in-stack ratio of the two (heaters, 32%, from SJVAPCD).	0.94	0.46		MMBtu/hr	NG	FarmersCoop Gin	Process Heaters_Dryers	0.32	FarmersCoopGin MMBtu/hr NG Process Heaters_Dryers	2.02	12.19	310.78	23.00	0.46	H705_1
2076	FRITO-LAY, INC.	9	COGENERATION FACILITY INCLUDING ALLISON 6.0 MW 53 MMBTU/HR GAS-FIRED GAS TURBINE ENGINE GENERATOR SET, 40 MMBTU/HR LOW-PRESSURE HEAT RECOVERY STEAM GENERATOR WITH COEN BURNER, PRE-COMBUSTION STEAM INJECTION NOZZLE, & ELDON HEAT RECLAIMER	299.50	109,324	295.158	3919.515	295.158	3919.515	14.1	Assumed stk ht is same as that of ovens/dryers at same facility from 2008 src test. Flowrate & diameter from Report 5768.pdf contained in 1303867.zip of info provided by district (2008 src test). Temperature is assumed based upon professional judgement.	3.88	3.88	6	MW	NG	Frito	Turbine-Small	0.1032	Frito 6 MW NG Turbine-Small	12.48	9.75	367.44	6.15	1.57	C2076_9
2076	FRITO-LAY, INC.	17	BAKED LINE #1 INCLUDING A 9.56 MMBTU/HR NATURAL GAS-FIRED BAKING OVEN, 10 MMBTU/HR NATURAL GAS-FIRED PRIMARY DRYER, STEAM HEATED FRYER WITH OIL MIST ELIMINATOR AND AMBIENT AIR COOLER	56.50	20,639	295.158	3919.515	295.158	3919.515	14.1	12 ft height, but assumed atop 20 ft bldg, from 2009 src test (1425573.pdf), temperature, diameter also from this test	0.73	0.73	9.56	MMBtu/hr	NG	Frito	Oven	0.32	Frito 9.56 MMBtu/hr NG Oven	2.35	9.75	427.44	0.07	0.66	O2076_17
2076	FRITO-LAY, INC.	18	BAKED LINE #2 INCLUDING 20.0 MMBTU/HR NATURAL GAS-FIRED BAKING OVEN AND 6.0 MMBTU/HR NATURAL GAS-FIRED FINISHING DRYER	81.60	29,784	295.158	3919.515	295.158	3919.515	14.1	12 ft height, but assumed atop 20 ft bldg, from 2009 src test (1425573.pdf), temperature, diameter also from this test	1.06	1.06	20	MMBtu/hr	NG	Frito	Oven	0.32	Frito 20 MMBtu/hr NG Oven	3.40	9.75	427.44	0.07	0.66	O2076_18
1118	HIGH SIERRA LIMITED	1	NOMINALLY RATED 24 MW GENERAL ELECTRIC LM-2500 NATURAL GAS FIRED GAS TURBINE ENGINE COGENERATION SYSTEM INCLUDING WINSTON 120 HB CENTRIFUGAL SEPARATOR	97.00	35,390	315.852	3931.393	315.852	3931.393	38.0	Stack parameters same as 38.7 MW Berry plant.	0.47	0.47	24	MW	NG	HiSierraLtd	Turbine-Large	0.17	HiSierraLtd 24 MW NG Turbine-Large	4.04	15.24	450.78	13.03	3.42	C1118_1
1118	HIGH SIERRA LIMITED	2	NOMINALLY RATED 24 MW GENERAL ELECTRIC LM-2500 NATURAL GAS FIRED TURBINE ENGINE COGENERATION SYSTEM INCLUDING WINSTON 120 HB CENTRIFUGAL SEPARATOR	97.00	35,390	315.852	3931.393	315.852	3931.393	38.0	Stack parameters same as 38.7 MW Berry plant.	0.47	0.47	24	MW	NG	HiSierraLtd	Turbine-Large	0.17	HiSierraLtd 24 MW NG Turbine-Large	4.04	15.24	450.78	13.03	3.42	C1118_2
1120	KERN FRONT LIMITED	1	NOMINALLY RATED 25 MW GENERAL ELECTRIC LM-2500 NATURAL GAS FIRED GAS TURBINE ENGINE COGENERATION SYSTEM WITH STEAM INJECTION	97.00	35,390	315.011	3932.143	315.011	3932.143	37.6	Stack parameters same as 38.7 MW Berry plant.	0.47	0.47	25	MW	NG	KernFrontLtd	Turbine-Large	0.17	KernFrontLtd 25 MW NG Turbine-Large	4.04	15.24	450.78	13.03	3.42	C1120_1

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1120	KERN FRONT LIMITED	2	NOMINALLY RATED 25 MW GENERAL ELECTRIC LM-2500 NATURAL GAS FIRED GAS TURBINE ENGINE COGENERATION SYSTEM WITH STEAM INJECTION	97.00	35,390	315.011	3932.143	315.011	3932.143	37.6	Stack parameters same as 38.7 MW Berry plant.	0.47	0.47	25	MW	NG	KernFrontLtd	Turbine-Large	0.17	KernFrontLtd 25 MW NG Turbine-Large	4.04	15.24	450.78	13.03	3.42	C1120_2
1678	KERN MEDICAL CENTER	1	16.8 MMBTU/HR NATURAL GAS/OIL FIRED WICKES BOILER #1	58.90	1,314	320.883	3917.211	320.883	3917.211	38.1	Assumed stack height based on professional judgement (considering size and type of operation).	0.28	0.02	16.8	MMBTU/HR	NG	KernMedCtr	Boiler/Steam Gen	0.1	KernMedCtr 16.8 MMBTU/HR NG Boiler/Steam Gen	2.45	10.00	373.00	10.00	0.30	B1678_1
37	KERN OIL & REFINING COMPANY	114	SOLAR CENTAUR C-50 COGENERATION SYSTEM WITH NATURAL GAS/KEROSENE FIRED SOLAR TURBINE, INC. GAS TURBINE ENGINE (GTE) WITH DRY LOW NOX (DLN) COMBUSTORS POWERING A 4.968 MEGAWATT ELECTRICAL GENERATOR, 23 MMBTU/HR NATURAL GAS FIRED DUCT BURNER, HEAT RECOVERY	84.20	24,176	325.564	3907.512	325.564	3907.512	42.7	Stack parameters assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	0.36	0.28	4.968	MW	NG	KernOil&RefCo	Turbine-Small	0.1032	KernOil&RefCo 4.968 MW NG Turbine-Small	3.51	13.00	367.44	6.15	1.57	C37_114
37	KERN OIL & REFINING COMPANY	1	120 MMBTU/HR CRUDE UNIT INCLUDING 2 DESALTERS, 4 FRACTIONATION VESSELS, STRIPPER, 2 ACCUMULATORS, DEPROPANIZER, KNOCKOUT DRUM SCRUBBER, 60 MMBTU/HR TULSA HEATERS INC. PROCESS HEATER, 60 MMBTU/HR BORN HEATER AND 15 HEAT EXCHANGERS	103.60	37,814	325.564	3907.512	325.564	3907.512	42.7	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.44	0.44	120	MMBTU/HR	NG	KernOil&RefCo	Process Heaters_Dryers	0.32	KernOil&RefCo 120 MMBTU/HR NG Process Heaters_Dryers	4.32	20.00	366.33	10.00	1.22	H37_1
88	KERN RIVER COGENERATION CO	1	75 MW GENERAL ELECTRIC MODEL 7EA NATURAL GAS-FIRED COMBUSTION TURBINE COGENERATION UNIT WITH DRY LOW NOX COMBUSTORS (KRCC UNIT #1)	1,629.60	594,804	321.992	3923.680	321.992	3923.680	40.5	Same assumptions as those for 40 MW cogen at Berry Petro in prior run.	7.34	7.34	75	MW	NG	KernRvrCogen	Turbine-Large	0.17	KernRvrCogen 75 MW NG Turbine-Large	67.90	15.24	450.78	13.03	3.42	C88_1
88	KERN RIVER COGENERATION CO	2	75 MW GENERAL ELECTRIC MODEL 7EA NATURAL GAS-FIRED COMBUSTION TURBINE COGENERATION UNIT WITH DRY LOW NOX COMBUSTORS (KRCC UNIT #2)	1,629.60	594,804	321.992	3923.680	321.992	3923.680	40.5	Same assumptions as those for 40 MW cogen at Berry Petro in prior run.	7.34	7.34	75	MW	NG	KernRvrCogen	Turbine-Large	0.17	KernRvrCogen 75 MW NG Turbine-Large	67.90	15.24	450.78	13.03	3.42	C88_2
88	KERN RIVER COGENERATION CO	3	75 MW GENERAL ELECTRIC MODEL 7EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR (CTG) WITH DRY LOW NOX COMBUSTOR TECHNOLOGY DISCHARGING TO ATMOSPHERE THROUGH A BYPASS STACK WHEN OPERATED IN SIMPLE CYCLE MODE OR THROUGH UNFIRED 450,000 LB/HR HEAT RECOVERY	552.80	108,624	321.992	3923.680	321.992	3923.680	40.5	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run, except temp assumed same as that used for Frito 6 MW cogen	2.49	1.34	75	MW	NG	KernRvrCogen	Turbine-Large	0.17	KernRvrCogen 75 MW NG Turbine-Large	23.03	15.24	367.44	13.03	3.42	C88_3
88	KERN RIVER COGENERATION CO	4	75 MW GENERAL ELECTRIC MODEL 7EA NATURAL GAS-FIRED COMBUSTION TURBINE WITH DRY LOW NOX COMBUSTORS (KRCC UNIT #4)	1,629.60	594,804	321.992	3923.680	321.992	3923.680	40.5	Same assumptions as those for 40 MW cogen at Berry Petro in prior run.	7.34	7.34	75	MW	NG	KernRvrCogen	Turbine-Large	0.17	KernRvrCogen 75 MW NG Turbine-Large	67.90	15.24	450.78	13.03	3.42	C88_4
3412	LA PALOMA GENERATING CO LLC	1	ABB GT-24 NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #1 WITH DRY LOW NOX COMBUSTORS, STEAM POWER AUGMENTATION, SELECTIVE CATALYTIC REDUCTION, STEAM TURBINE, AND ELECTRICAL GENERATOR (262 MW NOMINAL RATING)	511.40	146,001	252.109	3916.933	252.109	3916.933	31.4	Stack parameters from this combined-cycle PP assumed to be similar to that of HECA HRSG, except stack diameter set to 10 ft and stack height set to 100 ft.	2.98	2.33	262	MW	NG	LaPalomaGen	Turbine-Large	0.17	LaPalomaGen 262 MW NG Turbine-Large	21.31	36.60	345.00	12.50	5.49	T3412_1
3412	LA PALOMA GENERATING CO LLC	2	ABB GT-24 NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #2 WITH DRY LOW NOX COMBUSTORS, STEAM POWER AUGMENTATION, SELECTIVE CATALYTIC REDUCTION, STEAM TURBINE AND ELECTRICAL GENERATOR (262 MW NOMINAL RATING)	511.40	146,001	252.109	3916.933	252.109	3916.933	31.4	Stack parameters from this combined-cycle PP assumed to be similar to that of HECA HRSG, except stack diameter set to 10 ft and stack height set to 100 ft.	2.98	2.33	262	MW	NG	LaPalomaGen	Turbine-Large	0.17	LaPalomaGen 262 MW NG Turbine-Large	21.31	36.60	345.00	12.50	5.49	T3412_2
3412	LA PALOMA GENERATING CO LLC	3	ABB GT-24 NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #3 WITH DRY LOW NOX COMBUSTORS, STEAM POWER AUGMENTATION, SELECTIVE CATALYTIC REDUCTION, STEAM TURBINE, AND ELECTRICAL GENERATOR (262 MW NOMINAL RATING)	4,790.00	146,001	252.109	3916.933	252.109	3916.933	31.4	The daily value does not agree with the other three units at the site, nor the annual value; therefore, a value of 511.4 lb/day was used like the other sources of the same type at this facility. Stack parameters from this combined-cycle PP assumed to be similar to that of HECA HRSG, except stack diameter set to 10 ft and stack height set to 100 ft.	27.88	2.33	262	MW	NG	LaPalomaGen	Turbine-Large	0.17	LaPalomaGen 262 MW NG Turbine-Large	21.31	36.60	345.00	12.50	5.49	T3412_3
3412	LA PALOMA GENERATING CO LLC	4	ABB GT-24 NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #4 WITH DRY LOW NOX COMBUSTORS, STEAM POWER AUGMENTATION, OXIDATION CATALYST, SELECTIVE CATALYTIC REDUCTION, STEAM TURBINE, AND ELECTRICAL GENERATOR (262 MW NOMINAL RATING)	511.40	146,001	252.109	3916.933	252.109	3916.933	31.4	Stack parameters from this combined-cycle PP assumed to be similar to that of HECA HRSG, except stack diameter set to 10 ft and stack height set to 100 ft.	2.98	2.33	262	MW	NG	LaPalomaGen	Turbine-Large	0.17	LaPalomaGen 262 MW NG Turbine-Large	21.31	36.60	345.00	12.50	5.49	T3412_4

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
172	LIVE OAK LIMITED	1	NOMINALLY RATED 48 MW G.T.E. COGENERATION SYSTEM WITH SCR INCLUDING STEWART & STEVENSON GE LM-5000 GAS TURBINE GENERATOR, HEAT RECOVERY STEAM GENERATOR, AND INLET AIR ABSORPTION CHILLER AND HEAT EXCHANGER	138.70	50,626	317.772	3929.931	317.772	3929.931	38.9	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run, except temp assumed same as that used for Frito 6 MW cogen	0.65	0.65	48	MW	NG	LiveOakLtd	Turbine-Large	0.17	LiveOakLtd 48 MW NG Turbine-Large	5.78	15.24	367.44	13.03	3.42	C172_1
1251	MCKITTRICK LIMITED	1	48 MW COGENERATION SYSTEM WITH SCR INCLUDING STEWART & STEVENSON GE LM 5000 GAS-FIRED TURBINE, HEAT RECOVERY STEAM GENERATOR, AND INLET AIR ABSORPTION CHILLER AND HEAT EXCHANGER	147.90	53,969	258.102	3911.861	258.102	3911.861	25.0	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run, except temp assumed same as that used for Frito 6 MW cogen	1.08	1.08	48	MW	NG	McKittrickLtd	Turbine-Large	0.17	McKittrickLtd 48 MW NG Turbine-Large	6.16	15.24	367.44	13.03	3.42	C1251_1
2592	MID-SET COGENERATION COMPANY	1	39.86 MW GENERAL ELECTRIC, FRAME 6, MODEL PG6531(B) GAS-FIRED GAS TURBINE ENGINE COGENERATION SYSTEM.	438.20		266.214	3897.709	266.214	3897.709	22.3	Stack parameters same as 38.7 MW Berry plant.	3.59	-	39.86	MW	NG	Mid-SetCogen	Turbine-Large	0.17	Mid-SetCogen 39.86 MW NG Turbine-Large	18.26	15.24	450.78	13.03	3.42	C2592_1
91	MT POSO COGENERATION COMPANY	3	49.9 MW COAL/PETROLEUM COKE AND TIRE DERIVED FUEL (TDF) FIRED ATMOSPHERIC CIRCULATING FLUIDIZED BED COMBUSTOR COGENERATION POWER PLANT	1,406.40	513,336	318.228	3938.887	318.228	3938.887	44.1	Same stack assumptions as those for 40 MW cogen at Berry Petro in prior run.	5.82	5.82	49.9	MW	multi-fuel	MtPosoCogen	Fluidized bed-other	0.5	MtPosoCogen 49.9 MW multi-fuel Fluidized bed-other	58.60	15.24	450.78	13.03	3.42	C91_3
3340	N. W. LOST HILLS PETROLEUM HOLDINGS, LLC	1	WELL TEST FLARING OPERATION WITH FOUR PORTABLE WELL TEST FLARES EACH WITH A TWO PHASE SEPARATOR	396.70	19,948	313.990	3912.671	313.990	3912.671	30.9	Assumed same size/stack parameters as test flare at Pacific Process Sys (F2896_7), Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	2.34	0.32		MMBtu/hr	NG	LostHillsPetro	Flare	0.1	LostHillsPetro MMBtu/hr NG Flare	16.53	30.27	1273.00	20.00	3.67	F3340_1
5141	OASIS HOLSTEIN DAIRY	5	275 BHP CATERPILLAR MODEL C-9 SN CLJ03718 DIESEL-FIRED IC ENGINE POWERING AN AGRICULTURAL PUMP (LIMITED TO 150 BHP)	51.60	2,257	286.811	3930.827	286.811	3930.827	19.0	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000	0.50	0.06	275	BHP	Diesel	OasisDairy	IC Engine_Pump	0.2	OasisDairy 275 BHP Diesel IC Engine_Pump	2.15	3.00	622.00	57.50	0.13	P5141_5
1216	OCCIDENTAL OF ELK HILLS INC	87	44.58 MMBTU/HR WELL SAFETY FLARE AUTHORIZED TO OPERATE AT VARIOUS UNSPECIFIED LOCATIONS WITHIN THE LIGHT OIL WESTERN STATIONARY SOURCE.	72.80	26,572	256.078	3921.062	256.078	3921.062	28.4	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	0.47	0.47	44.58	MMBtu/hr		Oxy	Flare	0.1		3.03	18.79	1273.00	20.00	1.17	F1216_87
1216	OCCIDENTAL OF ELK HILLS INC	88	44.58 MMBTU/HR EMERGENCY WELL SAFETY FLARE	72.80	606	256.078	3921.062	256.078	3921.062	28.4	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	0.47	0.01	44.58	MMBtu/hr		Oxy	Flare	0.1		3.03	18.79	1273.00	20.00	1.17	F1216_88
2234	OCCIDENTAL OF ELK HILLS INC	52	ONE 24.5 MW NATURAL GAS FIRED GAS TURBINE COGENERATION SYSTEM, INCLUDING 250 MMBTU/HR GENERAL ELECTRIC MODEL LM-2500 GAS TURBINE, 103 MMBTU/HR DUCT BURNER ASSEMBLY, AND 150,000 LB/HR HEAT RECOVERY STEAM GENERATOR	98.60	35,989	275.202	3906.703			9.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in Price Industrial Noise Control Brochure	1.87	1.87	25	HP	NG	Large turbine	Turbine-Large	0.17		4.11	30.48	477.59	41.17	2.29	OxTBN52
2234	OCCIDENTAL OF ELK HILLS INC	53	ONE 24.5 MW NATURAL GAS FIRED GAS TURBINE COGENERATION SYSTEM, INCLUDING 250 MMBTU/HR GENERAL ELECTRIC MODEL LM-2500 GAS TURBINE, 103 MMBTU/HR DUCT BURNER ASSEMBLY, AND 150,000 LB/HR HEAT RECOVERY STEAM GENERATOR	98.60	35,989	275.339	3906.740			9.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in Price Industrial Noise Control Brochure	1.90	1.90	25	HP	NG	Oxy	Turbine-Large	0.17		4.11	30.48	477.59	41.17	2.29	OxTBN53
382	OCCIDENTAL OF ELK HILLS INC	675	12 MMBTU/HR THERMOFLUX NATURAL GAS-FIRED BOILER (10G) WITH A CALLIDUS TECHNOLOGIES MODEL CSG-12W-SPL LOW NOX BURNER WITH FGR	10.40	1,080	274.804	3906.973			9.8	Stack parameters given by similar project with 18 MMBtu heaters. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.19	0.06	12	MMBtu/hr	NG	Oxy	Heater	0.32		0.43	6.40	422.04	13.17	0.46	OxyBL675
382	OCCIDENTAL OF ELK HILLS INC	676	12 MMBTU/HR EVENFLUX NATURAL GAS-FIRED BOILER (18G) WITH CALLIDUS TECHNOLOGIES MODEL CSG-12W-SPL LOW NOX BURNER AND FGR	10.40	1,080	274.884	3906.967			9.7	Stack parameters given by similar project with 18 MMBtu heaters. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.19	0.06	12	MMBtu/hr	NG	Oxy	Heater	0.32		0.43	6.40	422.04	13.17	0.46	OxyBL676

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
382	OCCIDENTAL OF ELK HILLS INC	422	310 BHP CUMMINS DIESEL-FIRED STANDBY IC ENGINE (P1, UNX# 53262)	0.00	1,488	277.340	3904.990			9.2	Stack Parameters from Risk Management Guidance for the Permitting of New Stationary Permitting of New Stationary Diesel-Fueled Engines, CARB, October 2000. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	-	0.08	310	HP	Diesel	Oxy	IC Engine	0.2		3.10	3.00	622.00	57.41	0.13	OxyEE422
2234	OCCIDENTAL OF ELK HILLS INC	44	773 BHP WAUKESHA NATURAL GAS-FIRED STANDBY IC ENGINE (UNX #14166)	0.00	3,710	280.938	3909.025			3.8	Emissions from CAPCOA 2000 BACT clearinghouse "http://www.arb.ca.gov/bact/bact2to3.htm" (highest of all emission factors for similar sized natural gas IC engines 2g/bhp-hr). Stack parameters given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application No. 2008-178-TVR, DCP Midstream, LP, Okarche Natural Gas Processing Plant, (SIC 1321), NE/4 of Section 31, T15N, R8W, Kingfisher County, Oklahoma. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	-	0.48	773	HP	NG	Oxy	IC Engine	0.1		3.41	6.40	638.15	6.45	0.51	OxyEE44
2234	OCCIDENTAL OF ELK HILLS INC	46	793 BHP WAUKESHA NATURAL GAS-FIRED STANDBY IC ENGINE (UNX #13397)	0.00	3,806	285.184	3906.757			5.8	Emissions from CAPCOA 2000 BACT clearinghouse "http://www.arb.ca.gov/bact/bact2to3.htm" (highest of all emission factors for similar sized natural gas IC engines 2g/bhp-hr). Stack parameters given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application No. 2008-178-TVR, DCP Midstream, LP, Okarche Natural Gas Processing Plant, (SIC 1321), NE/4 of Section 31, T15N, R8W, Kingfisher County, Oklahoma. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	-	0.33	793	HP	NG	Oxy	IC Engine	0.1		3.50	6.40	638.15	6.45	0.51	OxyEE46
2234	OCCIDENTAL OF ELK HILLS INC	87	88 BHP WAUKESHA NATURAL GAS-FIRED STANDBY IC ENGINE (UNX #15556)	0.00	422	279.830	3903.249			9.5	PTE emission rate from Occidental of Elk Hills staff. Stack parameters given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application No. 2008-178-TVR, DCP Midstream, LP, Okarche Natural Gas Processing Plant, (SIC 1321), NE/4 of Section 31, T15N, R8W, Kingfisher County, Oklahoma. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	-	0.02	88	HP	NG	Oxy	IC Engine_Comp	0.6		2.11	6.40	638.15	6.45	0.51	OxyEE87
382	OCCIDENTAL OF ELK HILLS INC	677	12 MMBTU/HR NATURAL GAS-FIRED HEATER NO. 2 WITH A CALLIDUS TECHNOLOGIES MODEL CSG-12W-SPL LOW NOX BURNER AND FGR	10.40	1,080	274.994	3906.620			9.8	Stack parameters given by similar project with 18 MMBtu heaters. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.19	0.05	12	MMBtu/hr	NG	Oxy	Heater	0.32		0.43	6.40	422.04	13.17	0.46	OxyHT677
382	OCCIDENTAL OF ELK HILLS INC	678	12 MMBTU/HR NATURAL GAS-FIRED HEATER NO. 3 WITH A CALLIDUS TECHNOLOGIES MODEL CSG-12W-SPL LOW NOX BURNER WITH FGR	10.40	1,080	274.585	3906.689			10.1	Stack parameters given by similar project with 18 MMBtu heaters. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.19	0.05	12	MMBtu/hr	NG	Oxy	Heater	0.32		0.43	6.40	422.04	13.17	0.46	OxyHT678
382	OCCIDENTAL OF ELK HILLS INC	679	12 MMBTU/HR NATURAL GAS-FIRED HEATER NO. 4 WITH A CALLIDUS TECHNOLOGIES MODEL CSG-12W-SPL LOW NOX BURNER AND FGR	10.40	1,080	274.347	3906.783			10.3	Stack parameters given by similar project with 18 MMBtu heaters. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.18	0.05	12	MMBtu/hr	NG	Oxy	Heater	0.32		0.43	6.40	422.04	13.17	0.46	OxyHT679
382	OCCIDENTAL OF ELK HILLS INC	680	12 MMBTU/HR NATURAL GAS-FIRED HEATER NO. 5 WITH A CALLIDUS TECHNOLOGIES MODEL CSG-12W-SPL LOW NOX BURNER AND FGR	10.40	1,080	274.416	3906.804			10.2	Stack parameters given by similar project with 18 MMBtu heaters. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.19	0.05	12	MMBtu/hr	NG	Oxy	Heater	0.32		0.43	6.40	422.04	13.17	0.46	OxyHT680
382	OCCIDENTAL OF ELK HILLS INC	681	12 MMBTU/HR NATURAL GAS-FIRED HEATER NO. 6 WITH A CALLIDUS TECHNOLOGIES MODEL CSG-12W-SPL LOW NOX BURNER AND FGR	10.40	1,080	274.468	3906.795			10.2	Stack parameters given by similar project with 18 MMBtu heaters. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.19	0.05	12	MMBtu/hr	NG	Oxy	Heater	0.32		0.43	6.40	422.04	13.17	0.46	OxyHT681
2234	OCCIDENTAL OF ELK HILLS INC	10	5,500 BHP INGERSOLL-RAND MODEL 616KVR LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-41 UNX #16651)	480.20	175,258	274.334	3906.995	274333.677	3906994.665	10.2	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1998 and 4500 HP engines' flow rates.	8.59	8.59	5500	HP	NG	Oxy	IC Engine_Comp	0.6		20.01	12.19	657.59	23.73	0.91	OxyIC10
2234	OCCIDENTAL OF ELK HILLS INC	11	5,500 BHP INGERSOLL-RAND MODEL 616KVR LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-42 UNX #16650)	480.20	175,258	274.334	3907.041	274334.154	3907041.004	10.2	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1998 and 4500 HP engines' flow rates.	8.61	8.61	5500	HP	NG	Oxy	IC Engine_Comp	0.6		20.01	12.19	657.59	23.73	0.91	OxyIC11
2234	OCCIDENTAL OF ELK HILLS INC	12	2,000 BHP INGERSOLL-RAND MODEL 412KVS LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-43 UNX #13694)	185.20	67,593	274.335	3907.087	274334.624	3907086.734	10.2	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application Number 2002-532-TVR Northern Natural Gas Company Beaver County Compressor Station Section 24, T2N, R24E, IM, Beaver County	3.33	3.33	2000	HP	NG	Oxy	IC Engine_Comp	0.6		7.72	12.19	655.37	8.49	0.91	OxyIC12

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
2234	OCCIDENTAL OF ELK HILLS INC	123	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-14) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	284.683	3904.963			7.4	PTE emission rate from Occidental of Elk Hills staff. Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.12	0.12	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC123
2234	OCCIDENTAL OF ELK HILLS INC	124	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-15) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	285.632	3904.040			8.5	PTE emission rate from Occidental of Elk Hills staff. Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.11	0.11	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC124
2234	OCCIDENTAL OF ELK HILLS INC	127	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-25) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	271.233	3908.096	271232.602	3908096.170	12.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates.	0.07	0.07	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC127
2234	OCCIDENTAL OF ELK HILLS INC	128	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-26) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	280.702	3904.882			7.7	PTE emission rate from Occidental of Elk Hills staff. Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.12	0.12	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC128
2234	OCCIDENTAL OF ELK HILLS INC	129	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-27) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	269.683	3908.406	269682.920	3908405.754	13.9	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates.	0.07	0.06	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC129
2234	OCCIDENTAL OF ELK HILLS INC	130	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-28) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	269.720	3908.405	269719.504	3908405.377	13.9	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates.	0.07	0.06	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC130
2234	OCCIDENTAL OF ELK HILLS INC	131	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-29) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	281.144	3905.993	281143.801	3905993.216	6.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates.	0.14	0.14	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC131
2234	OCCIDENTAL OF ELK HILLS INC	132	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-30) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	281.143	3905.958	281142.523	3905957.862	6.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates.	0.14	0.14	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC132
2234	OCCIDENTAL OF ELK HILLS INC	133	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-31) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	278.590	3906.086	278590.101	3906086.223	7.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates.	0.12	0.12	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC133
2234	OCCIDENTAL OF ELK HILLS INC	134	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-32) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	278.591	3906.141	278591.271	3906140.787	7.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates.	0.12	0.12	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC134
2234	OCCIDENTAL OF ELK HILLS INC	135	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-33) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	269.909	3908.344	269909.132	3908343.967	13.7	PTE emission rate from Occidental of Elk Hills staff. Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates.	0.07	0.07	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC135
2234	OCCIDENTAL OF ELK HILLS INC	136	1834 HP NATURAL GAS-FIRED WAUKESHA IC ENGINE MODEL #7042 DRIVING A GAS COMPRESSOR (R-34) EQUIPPED WITH NON-SELECTIVE CATALYTIC REDUCTION, AIR/FUEL RATIO CONTROLLER, POSITIVE CRANKCASE VENTILATION, AND OPERATES AT VARIOUS UNSPECIFIED LOCATIONS WITHIN FACIL	5.00	1,808	269.868	3908.344	269868.279	3908344.388	13.8	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates.	0.07	0.07	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC136

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
2234	OCCIDENTAL OF ELK HILLS INC	15	5,500 BHP INGERSOLL-RAND MODEL 616KVR LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-36 UNX #13675)	480.20	175,258	274.561	3906.886	274560.624	3906886.226	10.1	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1998 and 4500 HP engines' flow rates.	8.71	8.71	5500	HP	NG	Oxy	IC Engine_Comp	0.6		20.01	12.19	657.59	23.73	0.91	OxyIC15
2234	OCCIDENTAL OF ELK HILLS INC	16	5,500 BHP INGERSOLL-RAND MODEL 616KVR LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-37 UNX #13674)	480.20	175,258	274.561	3906.932	274561.094	3906931.956	10.0	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1998 and 4500 HP engines' flow rates.	8.73	8.73	5500	HP	NG	Oxy	IC Engine_Comp	0.6		20.01	12.19	657.59	23.73	0.91	OxyIC16
2234	OCCIDENTAL OF ELK HILLS INC	17	5,500 BHP INGERSOLL-RAND MODEL 616KVR LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-38 UNX #13673)	480.20	175,258	274.562	3906.978	274561.565	3906977.685	10.0	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1998 and 4500 HP engines' flow rates.	8.75	8.75	5500	HP	NG	Oxy	IC Engine_Comp	0.6		20.01	12.19	657.59	23.73	0.91	OxyIC17
2234	OCCIDENTAL OF ELK HILLS INC	18	2,000 BHP INGERSOLL-RAND MODEL 412KVS LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-39 UNX #13672)	185.20	67,593	274.562	3907.023	274562.035	3907023.415	10.0	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application Number 2002-532-TVR Northern Natural Gas Company Beaver County Compressor Station Section 24, T2N, R24E, IM, Beaver County	3.38	3.38	2000	HP	NG	Oxy	IC Engine_Comp	0.6		7.72	12.19	655.37	8.49	0.91	OxyIC18
2234	OCCIDENTAL OF ELK HILLS INC	182	1,680 BHP WAUKESHA MODEL 7044 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-36)	6.20	1,795	278.959	3907.179			6.5	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.17	0.14	1680	HP	NG	Oxy	IC Engine_Comp	0.6		0.26	6.40	644.26	23.54	0.51	OxyIC182
2234	OCCIDENTAL OF ELK HILLS INC	183	1,680 BHP WAUKESHA MODEL 7044 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-37)	6.20	1,795	279.039	3905.333			8.0	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.14	0.11	1680	HP	NG	Oxy	IC Engine_Comp	0.6		0.26	6.40	644.26	23.54	0.51	OxyIC183
2234	OCCIDENTAL OF ELK HILLS INC	184	1,680 BHP WAUKESHA MODEL 7044 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-38)	6.20	1,795	281.228	3906.915			5.6	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.20	0.16	1680	HP	NG	Oxy	IC Engine_Comp	0.6		0.26	6.40	644.26	23.54	0.51	OxyIC184
2234	OCCIDENTAL OF ELK HILLS INC	185	1,680 BHP WAUKESHA MODEL 7044 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-39)	6.20	1,795	281.966	3905.227			7.1	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.16	0.13	1680	HP	NG	Oxy	IC Engine_Comp	0.6		0.26	6.40	644.26	23.54	0.51	OxyIC185
2234	OCCIDENTAL OF ELK HILLS INC	186	1,680 BHP WAUKESHA MODEL 7044 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-40)	6.20	1,795	283.285	3906.071			6.1	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.18	0.15	1680	HP	NG	Oxy	IC Engine_Comp	0.6		0.26	6.40	644.26	23.54	0.51	OxyIC186
2234	OCCIDENTAL OF ELK HILLS INC	187	1,680 BHP WAUKESHA MODEL 7044 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-41)	6.20	1,795	283.601	3904.700			7.5	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.15	0.12	1680	HP	NG	Oxy	IC Engine_Comp	0.6		0.26	6.40	644.26	23.54	0.51	OxyIC187
2234	OCCIDENTAL OF ELK HILLS INC	188	1,834 BHP WAUKESHA MODEL 7042 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-42)	6.80	1,960	267.920	3913.192			15.2	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.08	0.06	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC188
2234	OCCIDENTAL OF ELK HILLS INC	189	1,834 BHP WAUKESHA MODEL 7042 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-43)	6.80	1,960	269.555	3912.559			13.6	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.09	0.07	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC189

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
2234	OCCIDENTAL OF ELK HILLS INC	190	1,834 BHP WAUKESHA MODEL 7042 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-44)	6.80	1,960	272.140	3910.739			11.1	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.11	0.09	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC190
2234	OCCIDENTAL OF ELK HILLS INC	191	1,834 BHP WAUKESHA MODEL 7042 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-45)	6.80	1,960	273.617	3910.317			9.7	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.13	0.10	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC191
2234	OCCIDENTAL OF ELK HILLS INC	192	1,834 BHP WAUKESHA MODEL 7042 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-46)	6.80	1,960	275.516	3908.919			8.3	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.15	0.12	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC192
2234	OCCIDENTAL OF ELK HILLS INC	193	1,834 BHP WAUKESHA MODEL 7042 GSI NATURAL GAS-FIRED IC ENGINE WITH NSCR AND PCV POWERING A COMPRESSOR (R-47)	6.80	1,960	277.045	3908.524			7.1	Stack parameters given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1478 and 1998 HP engines' flow rates. Coordinates adjusted via Google Earth and facility footprint to reflect more reasonable or accurate location of source (instead of all facility sources co-located at one center point, as given by SJVAPCD).	0.18	0.14	1834	HP	NG	Oxy	IC Engine_Comp	0.6		0.28	6.40	644.26	23.54	0.51	OxyIC193
2234	OCCIDENTAL OF ELK HILLS INC	27	4,000 BHP DELAVAL MODEL HVA12 LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-9 UNX #11726)	349.20	127,460	275.287	3906.686	275286.962	3906686.061	9.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1998 and 4500 HP engines' flow rates.	6.66	6.66	4000	HP	NG	Oxy	IC Engine_Comp	0.6		14.55	12.19	649.26	17.15	0.91	OxyIC27
2234	OCCIDENTAL OF ELK HILLS INC	28	4,000 BHP DELAVAL MODEL HVA12 LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-10 UNX #11718)	349.20	127,460	275.299	3906.686	275299.458	3906685.628	9.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1998 and 4500 HP engines' flow rates.	6.67	6.67	4000	HP	NG	Oxy	IC Engine_Comp	0.6		14.55	12.19	649.26	17.15	0.91	OxyIC28
2234	OCCIDENTAL OF ELK HILLS INC	29	1,000 BHP WAUKESHA MODEL L7042GSI RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER, ENLARGED TURBOCHARGER NOZZLE RING, AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-11 UNX #13198)	38.10	13,905	275.369	3906.776	275368.986	3906775.771	9.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.74	0.74	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	691.48	9.66	0.51	OxyIC29
2234	OCCIDENTAL OF ELK HILLS INC	30	1,000 BHP WAUKESHA MODEL L7042GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER, ENLARGED TURBOCHARGER NOZZLE RING, AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-12 UNX #12493)	38.10	13,905	267.202	3909.933	267202.095	3909933.295	16.1	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.43	0.43	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	691.48	9.66	0.51	OxyIC30
2234	OCCIDENTAL OF ELK HILLS INC	31	1,000 BHP WAUKESHA MODEL L7042GSI RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER, ENLARGED TURBOCHARGER NOZZLE RING, AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-13 UNX #13409)	38.10	13,905	275.368	3906.691	275368.115	3906691.020	9.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.73	0.73	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	691.48	9.66	0.51	OxyIC31
382	OCCIDENTAL OF ELK HILLS INC	32	4,000 BHP INGERSOLL-RAND #512KVR NATURAL GAS FIRED I.C. ENGINE DRIVING A HIGH PRESSURE INJECTION COMPRESSOR #K-23 UNX# 13678 WITH FOLLOWING EQUIPMENT MANIFOLDED TOGETHER WITH HPI COMPRESSORS #K-24 & #K-25: ONE COALESCER INLET FILTER, ONE INLET AERIAL COOL	349.20	127,460	274.797	3906.851	274797.473	3906851.166	9.9	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITYAIR QUALITY DIVISION Evaluation of Permit Application No. 2003-395-TVR Panhandle Eastern Pipe Line Company Alva/North Hopeton Compressor Station Section 15, T26N, R14W Woods County, Oklahoma.	6.45	6.45	4000	HP	NG	Oxy	IC Engine_Comp	0.6		14.55	12.19	649.26	19.33	0.91	OxyIC32
382	OCCIDENTAL OF ELK HILLS INC	62	4,000 BHP INGERSOLL-RAND #512KVR NATURAL GAS FIRED I.C. ENGINE DRIVING A HIGH PRESSURE INJECTION COMPRESSOR #K-24 UNX# 13677 WITH FOLLOWING EQUIPMENT MANIFOLDED TOGETHER WITH HPI COMPRESSORS #K-23 & #K-25: ONE COALESCER INLET FILTER, ONE INLET AERIAL COO	349.20	127,460	274.797	3906.808	274797.034	3906808.485	9.9	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITYAIR QUALITY DIVISION Evaluation of Permit Application No. 2003-395-TVR Panhandle Eastern Pipe Line Company Alva/North Hopeton Compressor Station Section 15, T26N, R14W Woods County, Oklahoma.	6.43	6.43	4000	HP	NG	Oxy	IC Engine_Comp	0.6		14.55	12.19	649.26	19.33	0.91	OxyIC362
382	OCCIDENTAL OF ELK HILLS INC	63	4,000 BHP INGERSOLL-RAND #512KVR NATURAL GAS FIRED I.C. ENGINE DRIVING A HIGH PRESSURE INJECTION COMPRESSOR #K-25 UNX# 13676 WITH FOLLOWING EQUIPMENT MANIFOLDED TOGETHER WITH HPI COMPRESSORS #K-23 & #K-24: ONE COALESCER INLET FILTER, ONE INLET AERIAL COOL	349.20	127,460	274.797	3906.766	274796.595	3906765.804	9.9	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITYAIR QUALITY DIVISION Evaluation of Permit Application No. 2003-395-TVR Panhandle Eastern Pipe Line Company Alva/North Hopeton Compressor Station Section 15, T26N, R14W Woods County, Oklahoma.	6.42	6.42	4000	HP	NG	Oxy	IC Engine_Comp	0.6		14.55	12.19	649.26	19.33	0.91	OxyIC363

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
2234	OCCIDENTAL OF ELK HILLS INC	48	490 BHP CATERPILLAR MODEL G398 RICH BURN NATURAL GAS FIRED I.C. ENGINE, POWERING A GAS COMPRESSOR (K-68 UNX #54313)	18.70	6,813	274.540	3907.191	274539.981	3907191.335	9.9	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in Flow rate given in www.blm.gov APPENDIX B Cumulative Emissions Inventory B.1 STATE AGENCY-PERMITTED INDUSTRIAL SOURCE INVENTORY B.1.1 State Air-Quality Regulatory Authority	0.34	0.34	490	HP	NG	Oxy	IC Engine_Comp	0.6		0.78	4.57	644.26	14.56	0.30	OxyIC48
2234	OCCIDENTAL OF ELK HILLS INC	57	1,000 BHP NATURAL GAS FIRED WAUKESHA MODEL L7042 RICH BURN I.C. ENGINE WITH TURBOCHARGER, ENLARGED NOZZLE RING, AIR/FUEL RATIO CONTROL UNIT, AND A NONSELECTIVE THREE WAY CATALYTIC REDUCTION (NSCR) SYSTEM (K-53 UNX #13444)	38.10	13,905	269.036	3908.474	269036.307	3908473.701	14.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.48	0.48	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC57
2234	OCCIDENTAL OF ELK HILLS INC	58	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-49 UNX# 51286)	38.10	13,905	267.168	3909.934	267167.644	3909933.650	16.1	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.43	0.43	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC58
2234	OCCIDENTAL OF ELK HILLS INC	59	1,000 BHP WAUKESHA MODEL L7042-GSI RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-29 UNX# 13207)	38.10	13,905	269.200	3908.428	269200.483	3908427.799	14.4	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.48	0.48	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC59
2234	OCCIDENTAL OF ELK HILLS INC	60	650 BHP WAUKESHA MODEL L7042-GU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-54 UNX# 12877)	24.80	9,038	272.232	3906.862	272232.475	3906862.004	12.1	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application No. 2008-178-TVR, DCP Midstream, LP, Okarche Natural Gas Processing Plant, (SIC 1321), NE/4 of Section 31, T15N, R8W, Kingfisher County, Oklahoma	0.37	0.37	650	HP	NG	Oxy	IC Engine_Comp	0.6		1.03	6.40	638.15	6.45	0.51	OxyIC60
2234	OCCIDENTAL OF ELK HILLS INC	61	1,000 BHP WAUKESHA MODEL L7042GSI RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-52 UNX# 15676)	38.10	13,905	276.250	3906.804	276249.811	3906803.910	8.7	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.80	0.80	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC61
2234	OCCIDENTAL OF ELK HILLS INC	62	2,000 BHP INGERSOLL-RAND MODEL 412KVS LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-44 UNX# 13701)	185.20	67,593	281.577	3905.858	281576.572	3905858.280	6.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application Number 2002-532-TVR Northern Natural Gas Company Beaver County Compressor Station Section 24, T2N, R24E, IM, Beaver County	5.18	5.18	2000	HP	NG	Oxy	IC Engine_Comp	0.6		7.72	12.19	655.37	8.49	0.91	OxyIC62
2234	OCCIDENTAL OF ELK HILLS INC	63	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-48 UNX# 13435)	38.10	13,905	271.485	3907.901	271485.181	3907900.566	12.4	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.56	0.56	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC63
2234	OCCIDENTAL OF ELK HILLS INC	64	650 BHP WAUKESHA MODEL L7042-GU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-26 UNX# 11554)	24.80	9,038	270.303	3911.484	270303.430	3911484.365	12.8	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application No. 2008-178-TVR, DCP Midstream, LP, Okarche Natural Gas Processing Plant, (SIC 1321), NE/4 of Section 31, T15N, R8W, Kingfisher County, Oklahoma	0.35	0.35	650	HP	NG	Oxy	IC Engine_Comp	0.6		1.03	6.40	644.26	6.45	0.51	OxyIC64
2234	OCCIDENTAL OF ELK HILLS INC	65	650 BHP WAUKESHA MODEL L7042-GU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-27 UNX #12705)	24.80	9,038	270.341	3911.484	270341.234	3911483.975	12.8	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application No. 2008-178-TVR, DCP Midstream, LP, Okarche Natural Gas Processing Plant, (SIC 1321), NE/4 of Section 31, T15N, R8W, Kingfisher County, Oklahoma	0.35	0.35	650	HP	NG	Oxy	IC Engine_Comp	0.6		1.03	6.40	644.26	6.45	0.51	OxyIC65
2234	OCCIDENTAL OF ELK HILLS INC	66	650 BHP WAUKESHA MODEL L7042-GU RICH BURN NATURAL GAS FIRED I.C. ENGINE, EQUIPPED WITH CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-28 UNX# 12850)	24.80	9,038	270.381	3911.484	270380.562	3911483.569	12.7	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application No. 2008-178-TVR, DCP Midstream, LP, Okarche Natural Gas Processing Plant, (SIC 1321), NE/4 of Section 31, T15N, R8W, Kingfisher County, Oklahoma	0.36	0.35	650	HP	NG	Oxy	IC Engine_Comp	0.6		1.03	6.40	644.26	6.45	0.51	OxyIC66
2234	OCCIDENTAL OF ELK HILLS INC	67	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-30 UNX# 13426)	38.10	13,905	269.164	3908.428	269163.898	3908428.175	14.4	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.48	0.48	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC67

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
382	OCCIDENTAL OF ELK HILLS INC	670	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-31 UNX# 11553)	79.40	28,996	268.194	3909.319	268194.030	3909319.349	15.2	Stack parameters and coordinates given by Occidental Elk Hills engineer. OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.95	0.95	1000	HP	NG	Oxy	IC Engine_Comp	0.6		3.31	6.40	644.26	9.66	0.51	OxyIC670
382	OCCIDENTAL OF ELK HILLS INC	671	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-32 UNX# 18028)	79.40	28,996	268.231	3909.353	268230.964	3909352.813	15.1	Stack parameters and coordinates given by Occidental Elk Hills engineer. OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.96	0.96	1000	HP	NG	Oxy	IC Engine_Comp	0.6		3.31	6.40	644.26	9.66	0.51	OxyIC671
382	OCCIDENTAL OF ELK HILLS INC	672	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-33 UNX# 16453)	79.40	28,996	268.262	3909.392	268261.854	3909391.523	15.1	Stack parameters and coordinates given by Occidental Elk Hills engineer. OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.96	0.96	1000	HP	NG	Oxy	IC Engine_Comp	0.6		3.31	6.40	644.26	9.66	0.51	OxyIC672
2234	OCCIDENTAL OF ELK HILLS INC	68	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-31 UNX# 11553)	38.10	13,905	269.127	3908.429	269127.313	3908428.552	14.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.48	0.48	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC68
2234	OCCIDENTAL OF ELK HILLS INC	69	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-32 UNX# 18028)	38.10	13,905	269.091	3908.429	269090.729	3908428.929	14.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.48	0.48	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC69
2234	OCCIDENTAL OF ELK HILLS INC	70	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-33 UNX# 16453)	38.10	13,905	269.054	3908.429	269054.144	3908429.306	14.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.48	0.48	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC70
2234	OCCIDENTAL OF ELK HILLS INC	71	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-34 UNX# 13417)	38.10	13,905	269.018	3908.430	269017.559	3908429.683	14.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.48	0.48	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC71
2234	OCCIDENTAL OF ELK HILLS INC	72	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-35 UNX# 54626)	38.10	13,905	268.981	3908.430	268980.974	3908430.060	14.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.48	0.48	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC72
2234	OCCIDENTAL OF ELK HILLS INC	73	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-51 UNX# 13793)	38.10	13,905	276.414	3906.750	276413.903	3906750.391	8.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.81	0.81	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC73
2234	OCCIDENTAL OF ELK HILLS INC	74	1,000 BHP WAUKESHA MODEL L7042-GSIU RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-50 UNX# 13401)	38.10	13,905	276.450	3906.750	276450.487	3906750.015	8.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.81	0.81	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC74
2234	OCCIDENTAL OF ELK HILLS INC	75	2,000 BHP INGERSOLL-RAND MODEL 412KVS LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-45 UNX# 13706)	185.20	67,593	281.577	3905.898	281576.979	3905897.911	6.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application Number 2002-532-TVR Northern Natural Gas Company Beaver County Compressor Station Section 24, T2N, R24E, IM, Beaver County	5.21	5.21	2000	HP	NG	Oxy	IC Engine_Comp	0.6		7.72	12.19	644.26	8.49	0.91	OxyIC75
2234	OCCIDENTAL OF ELK HILLS INC	76	2,000 BHP INGERSOLL-RAND MODEL 412KVS LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-46 UNX# 13715)	185.20	67,593	281.577	3905.938	281577.386	3905937.542	6.4	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application Number 2002-532-TVR Northern Natural Gas Company Beaver County Compressor Station Section 24, T2N, R24E, IM, Beaver County	5.24	5.24	2000	HP	NG	Oxy	IC Engine_Comp	0.6		7.72	12.19	644.26	8.49	0.91	OxyIC76

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
2234	OCCIDENTAL OF ELK HILLS INC	77	2,000 BHP INGERSOLL-RAND MODEL 412KVS LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-47 UNX# 13716)	185.20	67,593	281.578	3905.977	281577.793	3905977.172	6.4	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application Number 2002-532-TVR Northern Natural Gas Company Beaver County Compressor Station Section 24, T2N, R24E, IM, Beaver County	5.27	5.27	2000	HP	NG	Oxy	IC Engine_Comp	0.6		7.72	12.19	644.26	8.49	0.91	OxyIC77
2234	OCCIDENTAL OF ELK HILLS INC	78	1,000 BHP WAUKESHA MODEL L7042 RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-58 UNX# 18033)	38.10	13,905	268.299	3909.428	268298.816	3909427.730	15.1	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.46	0.46	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC78
2234	OCCIDENTAL OF ELK HILLS INC	79	1,000 BHP WAUKESHA MODEL L7042 RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH TURBOCHARGER AND CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-57 UNX# 18017)	38.10	13,905	267.133	3909.934	267132.888	3909934.008	16.1	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	0.43	0.43	1000	HP	NG	Oxy	IC Engine_Comp	0.6		1.59	6.40	644.26	9.66	0.51	OxyIC79
2234	OCCIDENTAL OF ELK HILLS INC	80	1,000 BHP WAUKESHA MODEL L7042GL LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-STRATIFIED COMBUSTION SYSTEM, POWERING A GAS COMPRESSOR (K-59 UNX# 53881)	95.20	34,751	281.141	3905.915	281141.472	3905914.884	6.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	2.64	2.64	1000	HP	NG	Oxy	IC Engine_Comp	0.6		3.97	6.40	644.26	9.66	0.51	OxyIC80
2234	OCCIDENTAL OF ELK HILLS INC	81	1,000 BHP WAUKESHA MODEL L7042GL LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-STRATIFIED COMBUSTION SYSTEM, POWERING A GAS COMPRESSOR (K-60)	95.20	34,751	281.141	3905.880	281141.417	3905879.823	6.6	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Operating Permit Application No. 2007-102-O Canaan Resources, L.L.C. Ulan Compressor Station Latitude N 35.1010o, Longitude W 95.8514o Sections 8, Township 7N, Range 14E Indianola, Pittsburg County, Oklahoma.	2.62	2.62	1000	HP	NG	Oxy	IC Engine_Comp	0.6		3.97	6.40	644.26	9.66	0.51	OxyIC81
2234	OCCIDENTAL OF ELK HILLS INC	82	1,500 BHP WAUKESHA MODEL L7042 LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-STRATIFIED COMBUSTION SYSTEM, POWERING A GAS COMPRESSOR (K-70 UNX# 54508)	142.80	52,140	269.073	3908.473	269072.587	3908473.328	14.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application No. 95-412-C Associated Natural Gas, Inc. (ANGI) Creek Booster Station Section 7-17N-13E, Tulsa County, Oklahoma	1.79	1.80	1500	HP	NG	Oxy	IC Engine_Comp	0.6		5.95	6.40	644.26	16.16	0.51	OxyIC82
2234	OCCIDENTAL OF ELK HILLS INC	83	1,500 BHP WAUKESHA MODEL L7042 LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-STRATIFIED COMBUSTION SYSTEM, POWERING A GAS COMPRESSOR (K-71 UNX# 54497)	142.80	52,140	269.109	3908.473	269109.476	3908472.947	14.5	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION Evaluation of Permit Application No. 95-412-C Associated Natural Gas, Inc. (ANGI) Creek Booster Station Section 7-17N-13E, Tulsa County, Oklahoma	1.80	1.80	1500	HP	NG	Oxy	IC Engine_Comp	0.6		5.95	6.40	644.26	16.16	0.51	OxyIC83
2234	OCCIDENTAL OF ELK HILLS INC	84	490 BHP CATERPILLAR MODEL G398 RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-67 UNX# 54302)	18.70	6,813	274.503	3907.192	274503.397	3907191.711	10.0	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in Flow rate given in www.blm.gov APPENDIX B Cumulative Emissions Inventory B.1 STATE AGENCY-PERMITTED INDUSTRIAL SOURCE INVENTORY B.1.1 State Air-Quality Regulatory Authority	0.34	0.34	490	HP	NG	Oxy	IC Engine_Comp	0.6		0.78	4.57	644.26	14.56	0.30	OxyIC84
2234	OCCIDENTAL OF ELK HILLS INC	85	490 BHP CATERPILLAR MODEL G398 RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-66 UNX# 54299)	18.70	6,813	274.467	3907.192	274466.813	3907192.088	10.0	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in Flow rate given in www.blm.gov APPENDIX B Cumulative Emissions Inventory B.1 STATE AGENCY-PERMITTED INDUSTRIAL SOURCE INVENTORY B.1.1 State Air-Quality Regulatory Authority	0.34	0.34	490	HP	NG	Oxy	IC Engine_Comp	0.6		0.78	4.57	644.26	14.56	0.30	OxyIC85
2234	OCCIDENTAL OF ELK HILLS INC	86	490 BHP CATERPILLAR MODEL G398 RICH BURN NATURAL GAS FIRED I.C. ENGINE, WITH CATALYTIC CONVERTER, POWERING A GAS COMPRESSOR (K-69 UNX# 54318)	18.70	6,813	274.580	3907.191	274579.613	3907190.927	9.9	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate given in Flow rate given in www.blm.gov APPENDIX B Cumulative Emissions Inventory B.1 STATE AGENCY-PERMITTED INDUSTRIAL SOURCE INVENTORY B.1.1 State Air-Quality Regulatory Authority	0.35	0.34	490	HP	NG	Oxy	IC Engine_Comp	0.6		0.78	4.57	644.26	14.56	0.30	OxyIC86
2234	OCCIDENTAL OF ELK HILLS INC	9	5,500 BHP INGERSOLL-RAND MODEL 616KVR LEAN BURN NATURAL GAS FIRED I.C. ENGINE, WITH PRE-COMBUSTION CHAMBER, POWERING A GAS COMPRESSOR (K-40 UNX #16652)	480.20	175,258	274.333	3906.950	274333.213	3906949.545	10.2	Stack parameters and coordinates given by Occidental Elk Hills engineer. Flow rate calculated by interpolation from 1998 and 4500 HP engines' flow rates.	8.57	8.57	5500	HP	NG	Oxy	IC Engine_Comp	0.6		20.01	12.19	657.59	23.73	0.91	OxyIC9
73	OILDALE ENERGY LLC	2	COGENERATION SYSTEM WITH GENERAL ELECTRIC LM6000 GAS TURBINE ENGINE (GTE) WITH STEAM INJECTION, DUCT BURNER, OXIDATION CATALYST, WASTE HEAT RECOVERY SYSTEM, EMERGENCY BYPASS STACK, AND SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM	930.40	175,581	314.923	3920.673	314.923	3920.673	32.9	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run, except temp assumed same as that used for Frito 6 MW cogen, equip rating found via on-line literature search, www.gepower.com/prod_serv/products/aero_turbines/en/downloads/lm6000_sprint.pdf	5.16	2.67	43	MW	NG	OildaleEnergy	Turbine-Large	0.17	OildaleEnergy 43 MW NG Turbine-Large	38.77	15.24	367.44	13.03	3.42	C73_2

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
2896	PACIFIC PROCESS SYSTEMS	2	WELL TEST FLARING OPERATION WITH SIX 83.3 MMBTU/HR PORTABLE AIR-ASSISTED WELL TEST FLARES EACH WITH THREE PHASE SEPARATOR, AUTHORIZED AT VARIOUS SPECIFIED LOCATIONS	204.00	19,584	314.002	3913.237	314.002	3913.237	30.9	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	1.20	0.32	83.3	MMBtu/hr (SIX)	NG	PacifiProcSys	Flare	0.1	PacifiProcSys 83.3 MMBtu/hr (SIX) NG Flare	8.50	20.82	1273.00	20.00	1.60	F2896_2
2896	PACIFIC PROCESS SYSTEMS	7	10 MM SCF/DAY WELL TEST FLARE - VARIOUS UNSPECIFIED LOCATIONS	680.00	19,992	314.002	3913.237	314.002	3913.237	30.9	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	4.01	0.32	10	MMscf/day	NG	PacifiProcSys	Flare	0.1	PacifiProcSys 10 MMscf/day NG Flare	28.33	30.27	1273.00	20.00	3.67	F2896_7
892	PACTIV CORPORATION	4	POLYSTYRENE FLUFF RECLAIM OPERATION INCLUDING 17 TRIM GRINDERS, SIX RECLAIM GRANULATORS, FLUFF TRANSFER AND STORAGE, THREE RECLAIM EXTRUDER LINES, RECLAIMED RESIN STORAGE AND TRANSFER WITH VOC VAPOR COLLECTION AND SMITH ENGINEERING REGENERATIVE THERMAL OX	53.80	19,637	313.226	3921.580	313.226	3921.580	31.5	Assumed stack parameters based on professional judgement (considering size and type of operation). Assumed regenerative thermal oxidizer as a "Process Heater" and included the appropriate in-stack ratio (32%, from SJVAPCD).	0.31	0.31		MMBtu/hr	NG	PactivCorp	Process Heaters_Dryers	0.32	PactivCorp MMBtu/hr NG Process Heaters_Dryers	2.24	13.00	310.78	10.00	0.46	H892_4
377	PARAMOUNT FARMS	19	550.5 MMBTU/HR NATURAL GAS-FIRED PISTACHIO HULLING AND DRYING OPERATION #2	1,018.20	37,440	238.148	3949.077	238.148	3949.077	58.1	Assumed stack parameters based on professional judgement (considering size and type of operation). From the SJVAPCD, used the default in-stack NO2/NOx ratio for a "Boiler", an external combustion source with a slightly higher recommended ratio (10%) than that suggested for a dryer (6.88%) (this value appeared to be associated with a very specific dryer type (milk-tower dryer).	3.20	0.32	550.5	MMBTU/HR	NG	ParamtFarms	Process Heaters_Dryers	0.1	ParamtFarms 550.5 MMBTU/HR NG Process Heaters_Dryers	42.43	13.00	310.78	10.00	0.46	H377_19
377	PARAMOUNT FARMS	20	23.33 MMBTU/HR GAS-FIRED PISTACHIO NUT FINISHING OPERATION CONSISTING OF BIN DUMPERS, SURGE HOPPERS, BUCKET ELEVATORS, CONVEYORS, PRE-CLEANING EQUIPMENT, SIZE GRADERS, NEEDLE PICKERS, HAND SORTING TABLES, ELECTRONIC COLOR SORTERS AND ASPIRATORS WITH SPUN	124.80	10,400	238.148	3949.077	238.148	3949.077	58.1	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.39	0.09	23.33	MMBTU/HR	NG	ParamtFarms	Process Heaters_Dryers	0.32	ParamtFarms 23.33 MMBTU/HR NG Process Heaters_Dryers	5.20	13.00	310.78	10.00	0.46	H377_20
377	PARAMOUNT FARMS	21	PISTACHIO STORAGE OPERATION WITH 176-3 MMBTU/HR HEATERS, OPERATION MAY BE EQUIPPED WITH THE FOLLOWING PERMIT EXEMPT WET PROCESSING EQUIPMENT: STORAGE BIN(S), SILO(S), BUCKET ELEVATOR(S), SILO DISTRIBUTION CONVEYOR(S), BRIDGE CONVEYOR(S), AND BLANK SHELL S	316.20	13,728	238.148	3949.077	238.148	3949.077	58.1	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.99	0.12	3	MMBTU/HR	NG	ParamtFarms	Process Heaters_Dryers	0.32	ParamtFarms 3 MMBTU/HR NG Process Heaters_Dryers	13.18	13.00	310.78	10.00	0.46	H377_21
377	PARAMOUNT FARMS	3	396 MMBTU/HR PISTACHIO HULLING AND DRYING OPERATION #1 WITH TWELVE 27.0 MMBTU/HR DRYERS AND FOUR 18.0 MMBTU/HR DRYERS, OPERATION MAY BE EQUIPPED WITH THE FOLLOWING PERMIT EXEMPT WET PROCESSING EQUIPMENT: PISTACHIO HULLER/PEELER(S), WASH DECK(S), FLOAT TA	790.70	20,384	238.148	3949.077	238.148	3949.077	58.1	Assumed stack parameters based on professional judgement (considering size and type of operation). From the SJVAPCD, used the default in-stack NO2/NOx ratio for a "Boiler", an external combustion source with a slightly higher recommended ratio (10%) than that suggested for a dryer (6.88%) (this value appeared to be associated with a very specific dryer type (milk-tower dryer).	2.48	0.18	396	MMBTU/HR	NG	ParamtFarms	Process Heaters_Dryers	0.1	ParamtFarms 396 MMBTU/HR NG Process Heaters_Dryers	32.95	13.00	310.78	10.00	0.46	H377_3
377	PARAMOUNT FARMS	47	13.4 MMBTU/HR GAS FIRED ARTIFICIAL PISTACHIO OPENING OPERATION WITH 4-4.0 MMBTU/HR HEATERS DERATED BY ORIFICE DISK TO 0.75 MMBTU/HR, 4.0 MMBTU/HR NUT DRYER AND 6.0 MMBTU/HR ROTARY DRYER SERVED BY HIGH EFFICIENCY CYCLONE AND WET SCRUBBER, OPERATION MAY BE		6,656	238.148	3949.077	238.148	3949.077	58.1	Assumed stack parameters based on professional judgement (considering size and type of operation). Appears to include both heaters and dryers, so opted for "Process Heater" label and higher in-stack ratio of the two (heaters, 32%, from SJVAPCD).	-	0.06	13.4	MMBTU/HR	NG	ParamtFarms	Process Heaters_Dryers	0.32	ParamtFarms 13.4 MMBTU/HR NG Process Heaters_Dryers	0.76	13.00	310.78	10.00	0.46	H377_47
713	PARAMOUNT KING LLC	1	PISTACHIO RECEIVING/HULLING/DRYING OPERATION INCLUDING 4 RECEIVING PITS, 4 PRECLEANING LINES (EACH PRECLEANING LINE INCLUDES 2 CYCLONES FOR A TOTAL OF 8 CYCLONES), EIGHTEEN 27.0 MMBTU/HR GSI MODEL 2426 DRYERS, 2 PORTABLE SILO FANS, SAMPLE DRYER WITH TWO M	871.50	25,465	240.702	3962.915	240.702	3962.915	66.1	Assumed stack parameters based on professional judgement (considering size and type of operation).	2.41	0.19	27	MMBTU/HR	NG	ParamtFarms	Process Heaters_Dryers	0.32	ParamtFarms 27 MMBTU/HR NG Process Heaters_Dryers	36.31	13.00	310.78	10.00	0.46	H713_1
287	PETROLEUM PRODUCTION TESTING	1	41.5 MMBTU/HR VERTICAL WELL TEST FLARE INCLUDING PROPANE PILOT ASSEMBLY WITH AUTOMATIC ELECTRIONIC IGNITION, PROPANE TANK, AND PIPING, AND ONE GAS/LIQUID SEPARATOR - AUTHORIZED FOR VARIOUS UNSPECIFIED LOCATIONS IN SJVUAPCD	140.00	3,998	299.502	3915.199	299.502	3915.199	16.7	This flare was chosen as a representative/ conservative modeled source for Petroleum Production Testing (FAC ID 287); it is modeled alone to represent the facility in place of the others flares It has both a higher NOX daily emission rate and more conservative source parameters than the other four flares. Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	1.53	0.12	41.5	MMBtu/hr	Propane	PetroProdTest	Flare	0.1	PetroProdTest 41.5 MMBtu/hr Propane Flare	5.83	18.60	1273.00	20.00	1.13	F287_1
1372	PLAINS EXPLORATION & PRODUCTION COMPANY	26	32 MMBTU/HR NATURAL GAS/VAPOR RECOVERY GAS FIRED STEAM GENERATOR (#22 DIS# 45222-80) WITH FGR	122.90		263.658	3903.169	263.658	3903.169	21.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	1.05	-	32	MMBtu/hr	NG	Plains	Boiler/Steam Gen	0.1	Plains 32 MMBtu/hr NG Boiler/Steam Gen	5.12	7.32	421.89	5.51	1.07	B1372_26
1372	PLAINS EXPLORATION & PRODUCTION COMPANY	77	THERMALLY ENHANCED OIL RECOVERY OPERATION WELL VENT VAPOR COLLECTION SYSTEM WITH 364 STEAM DRIVE WELLS, HEAT EXCHANGER(S), GAS/LIQUID SEPARATOR(S), STORAGE VESSEL(S), SULFUR REMOVAL SYSTEM, COMPRESSOR(S), VAPOR PIPING TO STEAM GENERATORS, 33.3 MMBTU/HR S	54.40	19,856	263.658	3903.169	263.658	3903.169	21.4	Stack Parameters obtained from HRA section of SJVAPCD's "Notice of Preliminary Decision - ATC/Cert of Conformity" addressed to Chevron USA and dated 12-8-10. HRA dated 10-29-10. App Nos.: S-1141-26, 31, 515, 597 (all 62.5 MMBtu/hr steam generators). Obtained link in 1-21-11 e-mail from Glenn Reed, SJVAPCD.	0.46	0.46	33.3	MMBtu/hr	Vapor	Plains	Boiler/Steam Gen	0.1	Plains 33.3 MMBtu/hr Vapor Boiler/Steam Gen	2.27	7.32	421.89	5.51	1.07	B1372_77

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
1372	PLAINS EXPLORATION & PRODUCTION COMPANY	187	3.27 MW COGEN FACILITY INCLUDING SOLAR CENTAUR MODEL T4700 GAS FIRED TURBINE ENGINE GENERATOR SET WITH INLET AIR EVAPORATIVE COOLER, GAS FIRED DUCT BURNER, HEAT RECOVERY STEAM GENERATOR, AND KOCH COALESCER	229.90	83,914	263.658	3903.169	263.658	3903.169	21.4	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.96	1.96	3.27	MW	NG	Plains	Turbine-Small	0.1032	Plains 3.27 MW NG Turbine-Small	9.58	13.00	367.44	6.15	1.57	C1372A87
1372	PLAINS EXPLORATION & PRODUCTION COMPANY	188	3.27 MW COGEN FACILITY INCLUDING SOLAR CENTAUR MODEL T4700 GAS FIRED TURBINE ENGINE GENERATOR SET WITH INLET AIR EVAPORATIVE COOLER, GAS FIRED DUCT BURNER, HEAT RECOVERY STEAM GENERATOR, AND KOCH COALESCER	229.90	83,914	263.658	3903.169	263.658	3903.169	21.4	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.96	1.96	3.27	MW	NG	Plains	Turbine-Small	0.1032	Plains 3.27 MW NG Turbine-Small	9.58	13.00	367.44	6.15	1.57	C1372A88
1372	PLAINS EXPLORATION & PRODUCTION COMPANY	194	4.72 MW COGEN FACILITY INCLUDING SOLAR TAURUS MODEL 60-T73005 GAS FIRED TURBINE ENGINE GENERATOR SET WITH SOLONOX COMBUSTORS, GAS FIRED DUCT BURNER, AND HEAT RECOVERY STEAM GENERATOR	173.00	63,145	263.658	3903.169	263.658	3903.169	21.4	Stack parameter assumed same as that used for Frito 6 MW cogen in prior run (also based on assumptions).	1.47	1.47	4.72	MW	NG	Plains	Turbine-Small	0.1032	Plains 4.72 MW NG Turbine-Small	7.21	13.00	367.44	6.15	1.57	C1372A94
71	PLAINS LPG SERVICES, L.P.	14	BUTAMER-BUTANE ISOMERIZATION UNIT #2 WITH 105 MMBTU/HR GAS-FIRED HOT OIL HEATER H-202 EQUIPPED WITH CALLIDUS MODEL CUBR-12W LOW-NOX BURNERS AND INTERNAL FGR, WITH NITROGEN PURGE SYSTEM SERVING COMPRESSOR SEALS AND COMPRESSOR CRANKCASES	75.60	19,657	294.905	3924.976	294.905	3924.976	17.4	Assumed stack height and temp based on professional judgement. Calculated from fuel flow as found in SJVAPCD source test results (1422710.pdf), stack diam obtained from 1422710.pdf (src test in 2009)	0.79	0.57	105	MMBtu/hr	NG	Plains	Process Heaters_Dryers	0.32	Plains 105 MMBtu/hr NG Process Heaters_Dryers	3.15	12.19	310.78	2.78	1.82	H71_14
71	PLAINS LPG SERVICES, L.P.	4	BUTAMER-BUTANE ISOMERIZATION UNIT INCLUDING TWO BUTANE FEED DRYERS V-102A/B, HYDROGEN MAKE-UP DRYER V-106, TWO REGENERANT DRYERS V-107A/B, ONE 80 MMBTU/HR GAS-FIRED PROCESS OIL HEATER H-201 WITH SIX MODEL CUBR-10W LOW-NOX BURNERS AND FUEL PIPING SHARED WI	57.60	19,657	294.905	3924.976	294.905	3924.976	17.4	Assumed stack height and temp based on professional judgement. Calculated from fuel flow as found in SJVAPCD source test results (1422710.pdf), stack diam obtained from 1422710.pdf (src test in 2009). Appears to include both heaters and dryers, so opted for "Process Heater" label and higher in-stack ratio of the two (heaters, 32%, from SJVAPCD).	0.60	0.57	80	MMBtu/hr	NG	Plains	Process Heaters_Dryers	0.32	Plains 80 MMBtu/hr NG Process Heaters_Dryers	2.40	12.19	310.78	2.56	1.89	H71_4
1751	RIO BRAVO JASMIN	3	36 MW SOLID FUEL FIRED, CIRCULATING BED COMBUSTOR COGENERATION UNIT INCLUDING 389 MMBTU/HR COMBUSTOR WITH LOW-TEMPERATURE STAGED COMBUSTION, AMMONIA INJECTION, AND PULVERIZED LIMESTONE INJECTION - JASMIN FIELD	1,867.70		310.898	3941.867	310.898	3941.867	40.6	Stack parameters obtained from similar facilty type (San Joaquin Solar project).	8.39	-	36	MW	solid fuel	RioBravoJasmin	Solid Fuel combustor	0.5	RioBravoJasmin 36 MW solid fuel Solid Fuel combustor	77.82	30.48	383.00	25.00	2.00	C1751_3
883	RIO BRAVO POSO	3	36.0 MW SOLID FUEL FIRED CIRCULATING BED COMBUSTOR COGENERATION UNIT INCLUDING 389 MMBTU/HR COMBUSTOR WITH LOW-TEMPERATURE STAGED COMBUSTION, AMMONIA INJECTION, AND PULVERIZED LIMESTONE INJECTION - POSO CREEK	1,867.70	341,143	310.770	3937.089	310.770	3937.089	37.2	Stack parameters obtained from similar facilty type (San Joaquin Solar project).	9.16	4.58	36	MW	solid fuel	RioBravoPoso	Solid Fuel combustor	0.5	RioBravoPoso 36 MW solid fuel Solid Fuel combustor	77.82	30.48	383.00	25.00	2.00	C883_3
36	SAN JOAQUIN REFINING COMPANY	99	12.6 MMBTU/HR OIL/GAS FIRED STANDBY BOILER	138.40		314.132	3919.017	314.132	3919.017	31.8	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.80	-	12.6	MMBtu/hr	NG	SanJoaquinRefin	Boiler/Steam Gen	0.1	SanJoaquinRefin 12.6 MMBtu/hr NG Boiler/Steam Gen	5.77	20.00	373.00	10.00	0.30	B36_99
36	SAN JOAQUIN REFINING COMPANY	51	103.4 MMBTU/HR DIESEL TREATING UNIT WITH SULFUR RECOVERY UNIT, CAUSTIC SCRUBBER, AND SAFETY FLARE	82.70	30,169	314.132	3919.017	314.132	3919.017	31.8	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	0.48	0.47	103.4	MMBtu/hr	NG	SanJoaquinRefin	Flare	0.1	SanJoaquinRefin 103.4 MMBtu/hr NG Flare	3.45	21.67	1273.00	20.00	1.78	F36_51
36	SAN JOAQUIN REFINING COMPANY	1	79.2 MMBTU/HR ATMOSPHERIC/VACUUM CRUDE UNIT #4 WITH PREFLASH COLUMN, FRACTIONATOR, VACUUM DISTILLATION COLUMN WITH MECHANICAL VACUUM PRODUCING SYSTEM, 27 MMBTU/HR GAS/OIL/WASTE GAS FIRED NATURAL DRAFT VACUUM HEATER #VH-4 WITH THREE ZEECO CLSF 11 LOW NOX B	139.30	9,559	314.132	3919.017	314.132	3919.017	31.8	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.80	0.15	79.2	MMBtu/hr	NG	SanJoaquinRefin	Process Heaters_Dryers	0.32	SanJoaquinRefin 79.2 MMBtu/hr NG Process Heaters_Dryers	5.80	20.00	366.33	10.00	1.22	H36_1
3746	SUNRISE POWER COMPANY	1	160 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATAL	1,170.90	155,669	265.036	3898.864	265.036	3898.864	22.5	Stack parameters for this combined-cycle PP assumed to be identical to that of Elk Hills 160 PP w/ HRSG. Stack parameters from this combined-cycle PP assumed to be similar to that of HECA HRSG, except stack diameter set to 10 ft and stack height set to 100 ft.	9.51	3.47	160	MW	NG	Sunrise	Turbine-Large	0.17	Sunrise 160 MW NG Turbine-Large	48.79	36.60	345.00	12.50	5.49	T3746_1
3746	SUNRISE POWER COMPANY	2	160 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATAL	1,170.90	155,669	265.036	3898.864	265.036	3898.864	22.5	Stack parameters for this combined-cycle PP assumed to be identical to that of Elk Hills 160 PP w/ HRSG. Stack parameters from this combined-cycle PP assumed to be similar to that of HECA HRSG, except stack diameter set to 10 ft and stack height set to 100 ft.	9.51	3.47	160	MW	NG	Sunrise	Turbine-Large	0.17	Sunrise 160 MW NG Turbine-Large	48.79	36.60	345.00	12.50	5.49	T3746_2

FACID	Facility Name	Permit Number	Equipment Description	NOx Lb-Day	NOx Lb-Yr	UTME NAD83 Z11 (km)	UTMN NAD83 Z11 (km)	SJVAPCD UTME NAD83 Z11	SJVAPCD UTMN NAD83 Z11	Distance from HECA (km)	Extra Notes/Assumptions	Q/D -1 [(ton/yr)/km] (based on daily emissions)	Q/D - 2 [(ton/yr)/km] (based on annual emissions)	Eqp Rating	Rating Units	Fuel	Short Facility Name	Short Equip Description	In-stack Ratio (NO2/NOx)	MODEL Src Description	NOx Emissions Lb-Hour	HS (m)	TS (K)	VS (m/s)	DS (m)	MODEL Src ID
511	SYCAMORE COGENERATION CO	1	75 MW GENERAL ELECTRIC MODEL 7EA NATURAL GAS-FIRED COMBUSTION TURBINE WITH DRY LOW NOX COMBUSTORS	1,629.60	594,841	319.832	3924.984	319.832	3924.984	38.9	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run	7.65	7.65	75	MW	NG	SycamoreCogen	Turbine-Large	0.17	SycamoreCogen 75 MW NG Turbine-Large	67.90	15.24	450.78	13.03	3.42	C511_1
511	SYCAMORE COGENERATION CO	2	75 MW GENERAL ELECTRIC MODEL 7EA NATURAL GAS-FIRED COMBUSTION TURBINE COGENERATION UNIT WITH GE ENHANCED DRY LOW NOX DLN1+ COMBUSTORS DISCHARGING TO ATMOSPHERE THROUGH A BYPASS STACK WHEN OPERATED IN SIMPLE CYCLE MODE OR THROUGH UNFIRED 450,000 LB/HR HEAT	552.80	108,624	319.832	3924.984	319.832	3924.984	38.9	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run	2.59	1.40	75	MW	NG	SycamoreCogen	Turbine-Large	0.17	SycamoreCogen 75 MW NG Turbine-Large	23.03	15.24	450.78	13.03	3.42	C511_2
511	SYCAMORE COGENERATION CO	3	75 MW GENERAL ELECTRIC MODEL 7EA NATURAL GAS-FIRED COMBUSTION TURBINE COGENERATION UNIT WITH DRY LOW NOX COMBUSTORS (SYCAMORE #3)	1,629.60	594,804	319.832	3924.984	319.832	3924.984	38.9	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run	7.65	7.65	75	MW	NG	SycamoreCogen	Turbine-Large	0.17	SycamoreCogen 75 MW NG Turbine-Large	67.90	15.24	450.78	13.03	3.42	C511_3
511	SYCAMORE COGENERATION CO	4	75 MW GENERAL ELECTRIC MODEL 7EA NATURAL GAS-FIRED COMBUSTION TURBINE WITH DRY LOW NOX COMBUSTORS	1,629.60	594,841	319.832	3924.984	319.832	3924.984	38.9	Stack parameter assumed same as that used for 38.7 MW cogen at Berry Petro in prior run	7.65	7.65	75	MW	NG	SycamoreCogen	Turbine-Large	0.17	SycamoreCogen 75 MW NG Turbine-Large	67.90	15.24	450.78	13.03	3.42	C511_4
44	TRICOR REFINING, LLC	5	99.9 MMBTU/HR NATURAL GAS-FIRED ZURN MODEL 15M KEYSTONE BOILER WITH COEN STAGED AIR BURNER AND FLUE GAS RECIRCULATION	74.30	27,120	317.277	3921.213	317.277	3921.213	35.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.38	0.38	99.9	MMBTU/HR	NG	TricorRef	Boiler/Steam Gen	0.1	TricorRef 99.9 MMBTU/HR NG Boiler/Steam Gen	3.10	13.00	373.00	10.00	0.61	B44_5
44	TRICOR REFINING, LLC	1	61 MMBTU/HR CRUDE FRACTIONATION PLANT INCLUDING LIQUID RING STAGED VACUUM PUMP WITH SEPARATOR, FLAME ARRESTOR, EMERGENCY VENT STACK, GAS/LIQUID SEPARATOR, THREE VACUUM VESSELS, ONE ATMOSPHERIC VESSEL, AND FOUR HEATERS		5,255	317.277	3921.213	317.277	3921.213	35.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	-	0.07	61	MMBTU/HR	NG	TricorRef	Process Heaters_Dryers	0.32	TricorRef 61 MMBTU/HR NG Process Heaters_Dryers	0.60	13.00	310.78	10.00	0.46	H44_1
44	TRICOR REFINING, LLC	145	ASPHALT AIR BLOWING OPERATION (STILL #1) WITH 690 BBL STILL, HOT OIL EXPANSION TANK, SEAL POT/HEAVY GAS OIL SCRUBBER, FIN FAN COOLER, AND 64.3 MMBTU/HR NATURAL GAS-FIRED OFFGAS INCINERATOR/PROCESS HEATER	77.10	20,550	317.277	3921.213	317.277	3921.213	35.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.40	0.29	64.3	MMBTU/HR	NG	TricorRef	Process Heaters_Dryers	0.32	TricorRef 64.3 MMBTU/HR NG Process Heaters_Dryers	3.21	13.00	310.78	10.00	0.46	H44_145
44	TRICOR REFINING, LLC	2	SOLVENT EXTRACTION PLANT INCLUDING AIR STRIPPER, TWO ROTATING DISC COLUMNS, AND 40 MMBTU/HR SOLVENT PLANT VERTICAL CYLINDRICAL TYPE HOT OIL HEATER WITH A ZEECO MODEL GLSF-16 LOW NOX BURNER	140.20	13,556	317.277	3921.213	317.277	3921.213	35.3	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.72	0.19	40	MMBTU/HR	NG	TricorRef	Process Heaters_Dryers	0.32	TricorRef 40 MMBTU/HR NG Process Heaters_Dryers	5.84	13.00	310.78	10.00	0.46	H44_2
1737	VINTAGE PRODUCTION CALIFORNIA LLC	157	63,000 GALLON (1,500 BBL) FIXED ROOF WASH TANK (T-01) WITH VAPOR CONTROL SHARED WITH S-1737-158, '-159, '-160, AND '-161 VENTING TO GAS SALES LINE, 41.7 MMBTU/HR COANDA TIP FLARE, AND/OR 2.0 MMBTU/HR PRODUCTION HEATER (S-1737-160)	208.00	30,564	304.180	3908.628	304.180	3908.628	21.4	Effective stack diameter and height calculated, temperature and exit velocity estimated for all flares	1.78	0.71	41.7	MMBtu/hr	Vapor	Vintage	Flare	0.1	Vintage 41.7 MMBtu/hr Vapor Flare	8.67	18.61	1273.00	20.00	1.13	F1737A57
1737	VINTAGE PRODUCTION CALIFORNIA LLC	168	126,000 GALLON FIXED ROOF CRUDE OIL GAUGE STORAGE TANK, 3-PHASE SEPARATOR, TWO HEATER TREATERS (EACH WITH PERMIT EXEMPT BURNER(S) RATED AT 5 MMBTU/HR OR LESS), TWO 2-PHASE SEPARATORS SERVED BY VAPOR RECOVERY SYSTEM SHARED WITH TANKS S-1737-169, '-170, AND	54.30	19,820	304.180	3908.628	304.180	3908.628	21.4	Assumed stack parameters based on professional judgement (considering size and type of operation).	0.46	0.46	5	MMBtu/hr (TWO)	Vapor	Vintage	Process Heaters_Dryers	0.32	Vintage 5 MMBtu/hr (TWO) Vapor Process Heaters_Dryers	2.26	13.00	310.78	10.00	0.46	H1737A68
4294	WORLD OIL CORP.	1	SOIL REMEDIATION OPERATION WITH 4,000,000 BTU/HR THERMAL OXIDIZER, 92 MMBTU/HR JOHN ZINK FLARE WITH UP TO THREE 500 CFM BLOWERS, LIQUID HYDROCARBON REMOVAL SYSTEM SERVING EXTRACTION WELLS, ONE 500 GALLON TANK, AND ONE 4000 GALLON CONDENSATE STORAGE TANK	309.10	49,999	309.943	3916.629	309.943	3916.629	27.2	Assumed stack parameters based on professional judgement (considering size and type of operation). Assumed thermal oxidizer as a "Process Heater" and included the appropriate in-stack ratio (32%, from SJVAPCD).	2.07	0.92	4	MMBtu	NG	WorldOil	Process Heaters_Dryers	0.32	WorldOil 4 MMBtu NG Process Heaters_Dryers	12.88	7.62	394.11	10.00	0.46	H4294_1

Attachment B

SJVAPCD, Permit Services Department. Villalvazo, Leland and Ester Davila. Procedures for Downloading and Processing NCDC Meteorological Data. May 2010

Procedures for Downloading and Processing NCDC Meteorological Data

Prepared by
San Joaquin Valley APCD
Permit Services Department

Leland Villalvazo, Supervising AQS
Ester Davila, Supervising AQS

NCDC General Statement:

Due to various Federal Laws and Regulations, NOAA National Climatic Data Centers (NCDC) is required to charge for some of its online data to recover the cost of data dissemination. This includes hardware and personnel costs incurred by each Data Center. Charges are required for most domains (e.g., .com, .org, .net). All online data are now free for all .gov, .edu, .k12, .mil, .us, and a few other specific domains. Please see NNDC's Free Data Distribution Statement (**http://www.ncdc.noaa.gov/oa/nndc/freedata.pdf)** (PDF Format) for further information on our FREE data policy. For information on how free access is granted via our web systems, please visit the Free Access (***http://www.ncdc.noaa.gov/oa/about/ncdchelp.html#FREE***) section of the NCDC help page (***http://www.ncdc.noaa.gov/oa/about/ncdchelp.html***)

Questions/Comments can be directed to: nndc.webmaster@noaa.gov

Introduction:

The following procedures are designed in a cookbook fashion to provide the user a step by step approach to downloading and processing local meteorological data. We hope that this approach will allow large and small Districts the ability to generate their own AERMOD data without the cost of hiring a third party. Or if a third party is hired, we hope that this approach will provide enough information to understand the steps that may be taken to process the raw data collected at the met tower(s) into the final met data used in AERMOD.

Where to Start:

The user needs to determine if their organization has FREE access rights to the online NCDC data. The user should go to the following website **Listing of REMOTE Environment Variables** (http://www.ncdc.noaa.gov/whoami/whoami) to determine if the user has one of the acceptable extensions (gov, edu, k12, mil, and us). The user should see his/her *Host Name* and the extension that has been determined.

If the *Host Name* does not have one of the acceptable extensions the user has two options 1) Contact their IT department for assistance or 2) email nndc.webmaster@noaa.gov and explain in the email 1) that you work for an APCD or AQMD in California, 2) that your IP does not have one of the acceptable extensions, 3) what the data is going to be used for (Regulatory Dispersion Modeling with AERMOD), 4) Your contact information, and 5) Request an account or other means that can be used to download the data for free. If NCDC accepts your explanation they will issue a user name and password that can be used to access the online NCDC data.

I have Access, Now What?

Now that you have access to the NCDC's data you will need to follow the steps below to download the quality controlled data.

NCDC Access Type:

There are two types of access rights we will be dealing with in the following steps: 1) Free Access and 2) Free Account Access.

Free Access: Users that have one of the acceptable IP extension determined above:
Free Account Access: Users that have been given an account by NCDC to access the online data

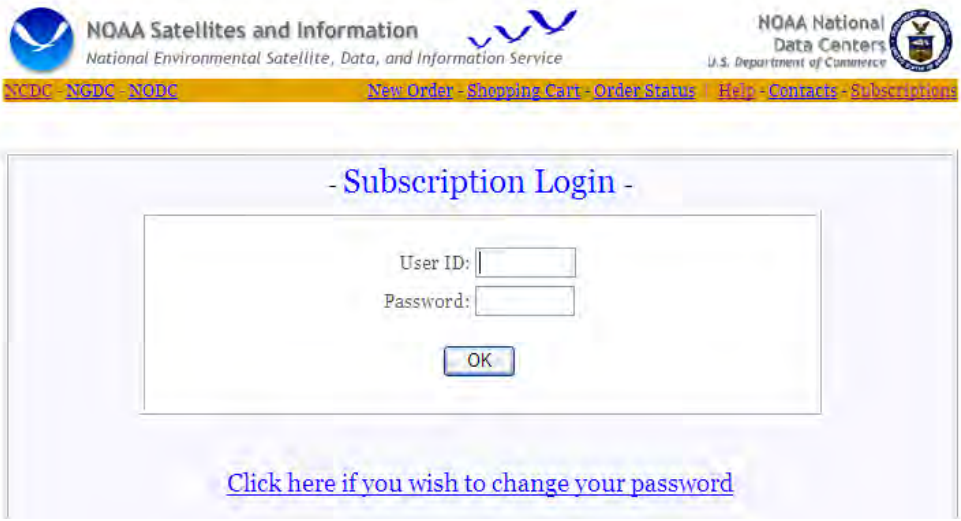
Free Access:
Users with this type of access should use the following steps to access the online data provided by NCDC.

> **Option 1:**
> To access data prior to Jan 2005 use this link
> **Unedited**(http://cdo.ncdc.noaa.gov/ulcd/ULCD)
>
> **Option 2:**
> To access data after Jan 2005 use this link **Quality Controlled**
> (http://cdo.ncdc.noaa.gov/qclcd/QCLCD?prior=N)

Now skip to Step 5 below (The screen shots below are based on Option 2)

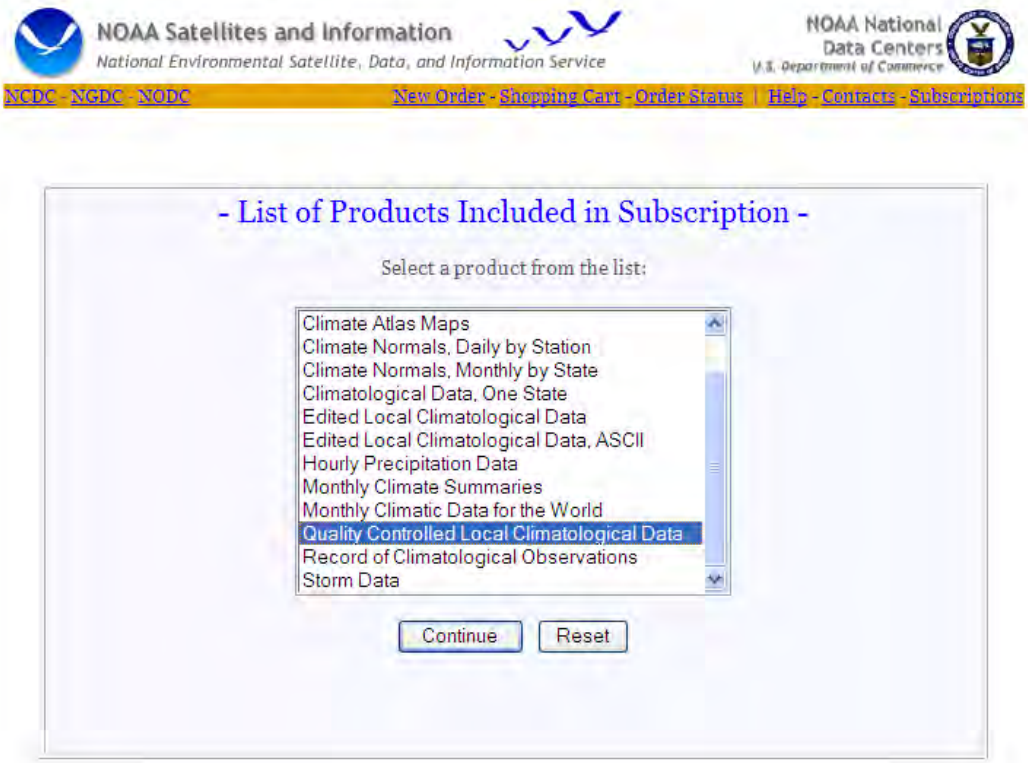
Free Account Access:
Users with this type of access should use the following steps to access the online data provided by NCDC.

Step1 - Login into the NCDC https://ols.nndc.noaa.gov/sub-login.html



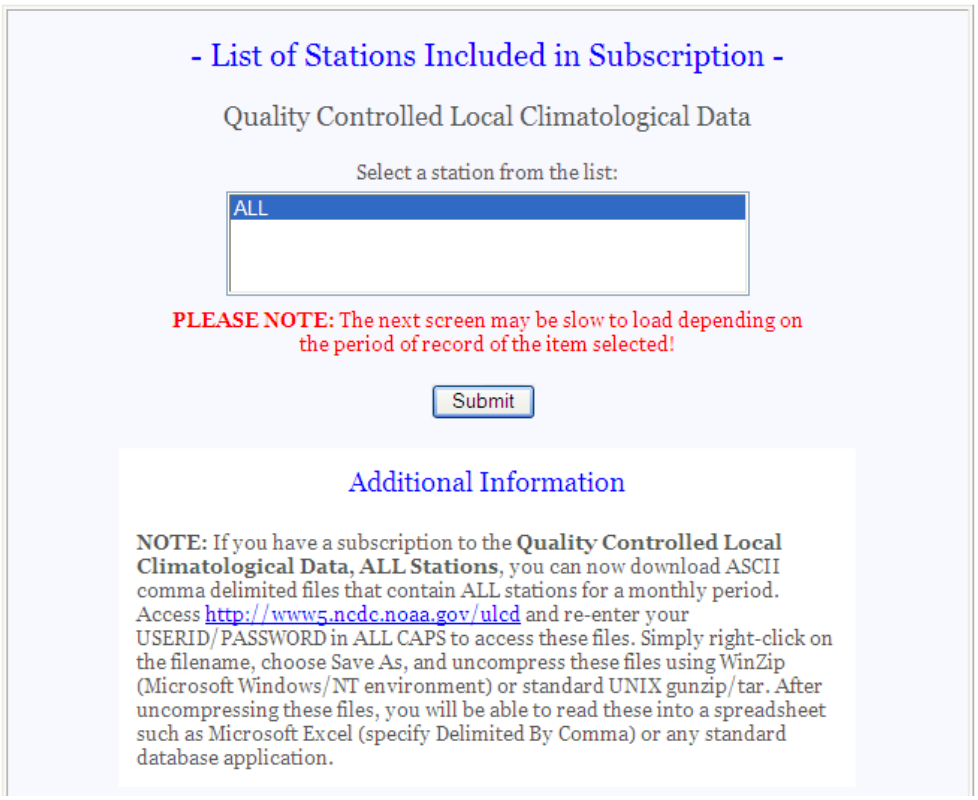
Enter your User ID and Password then click “OK”

Step 2 – Select data type "**Quality Controlled Local Climatological Data**"



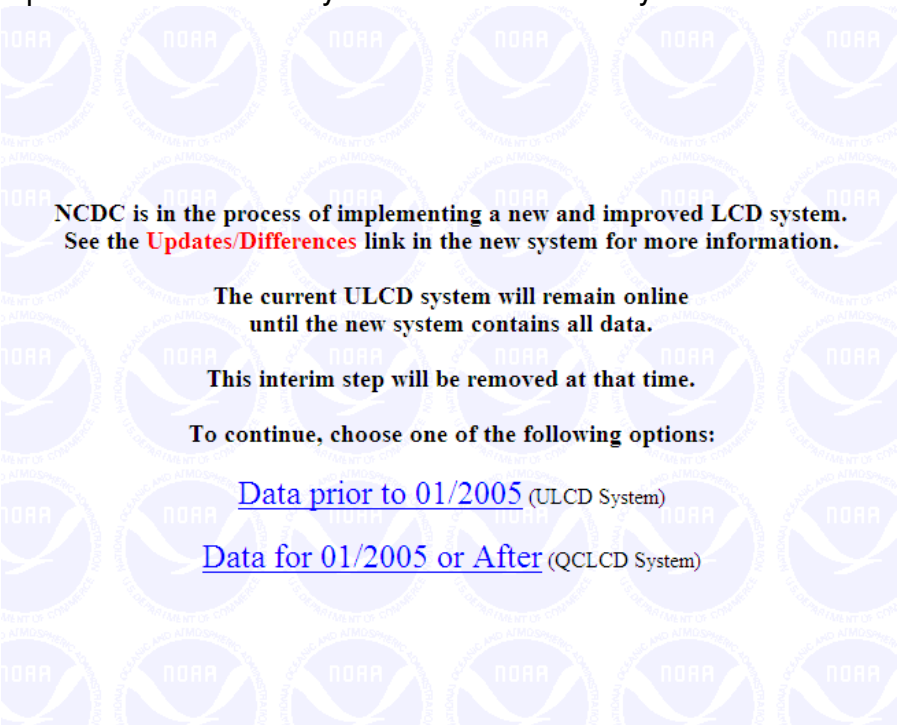
Select "Quality Controlled Local Climatological Data" then click "Continue"

Step 3 – Select "**All**" or a specific station if available



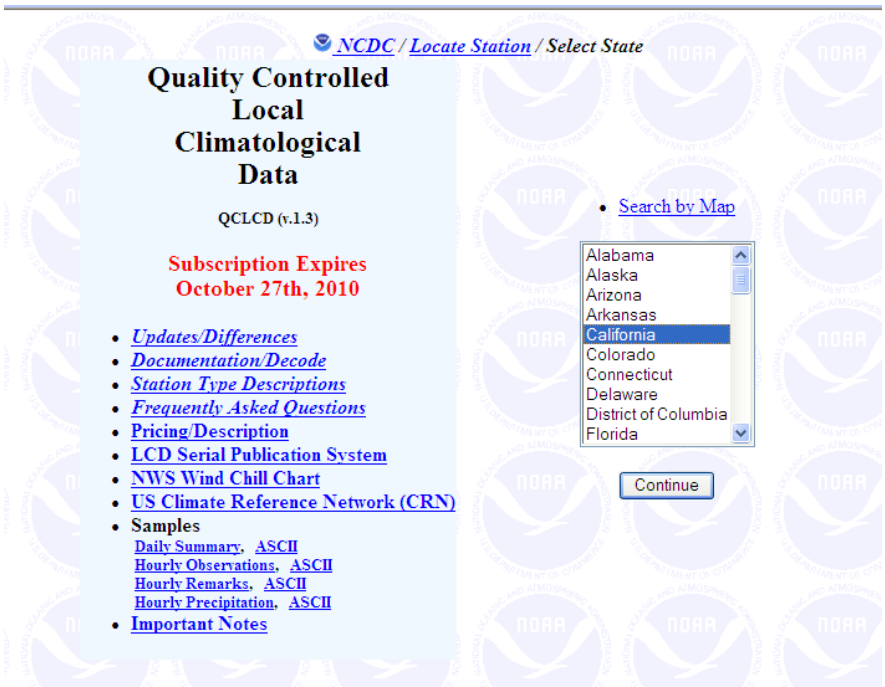
Select "ALL" then click "submit"

Step 4 – Select data period before January 2005 or After January 2005



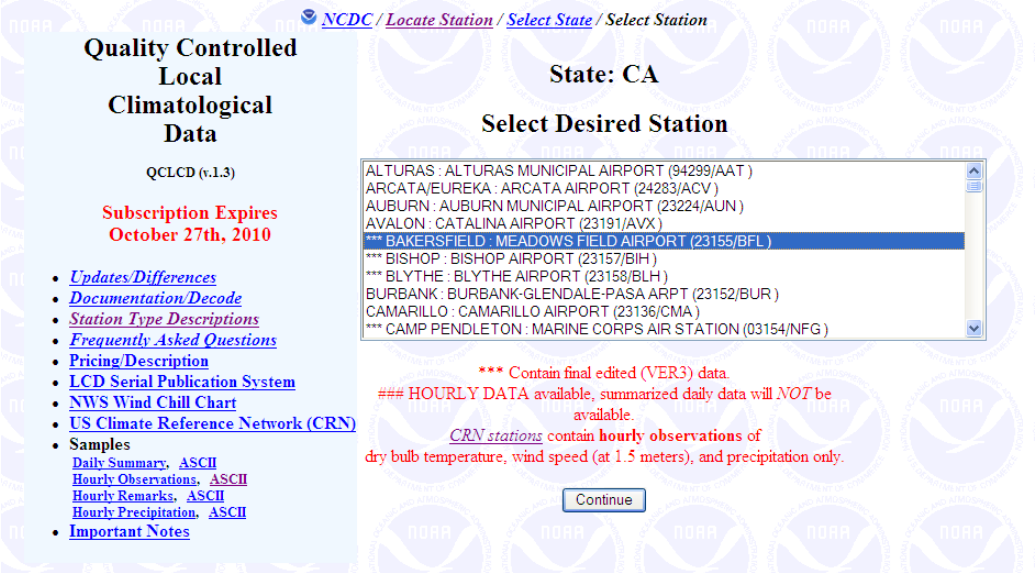
For this walk through click “Data for 01/2005 or After”

Step 5 – Select a state



Select “California” from the list then click “Continue”

Step 6 – Select the meteorological station of interest.



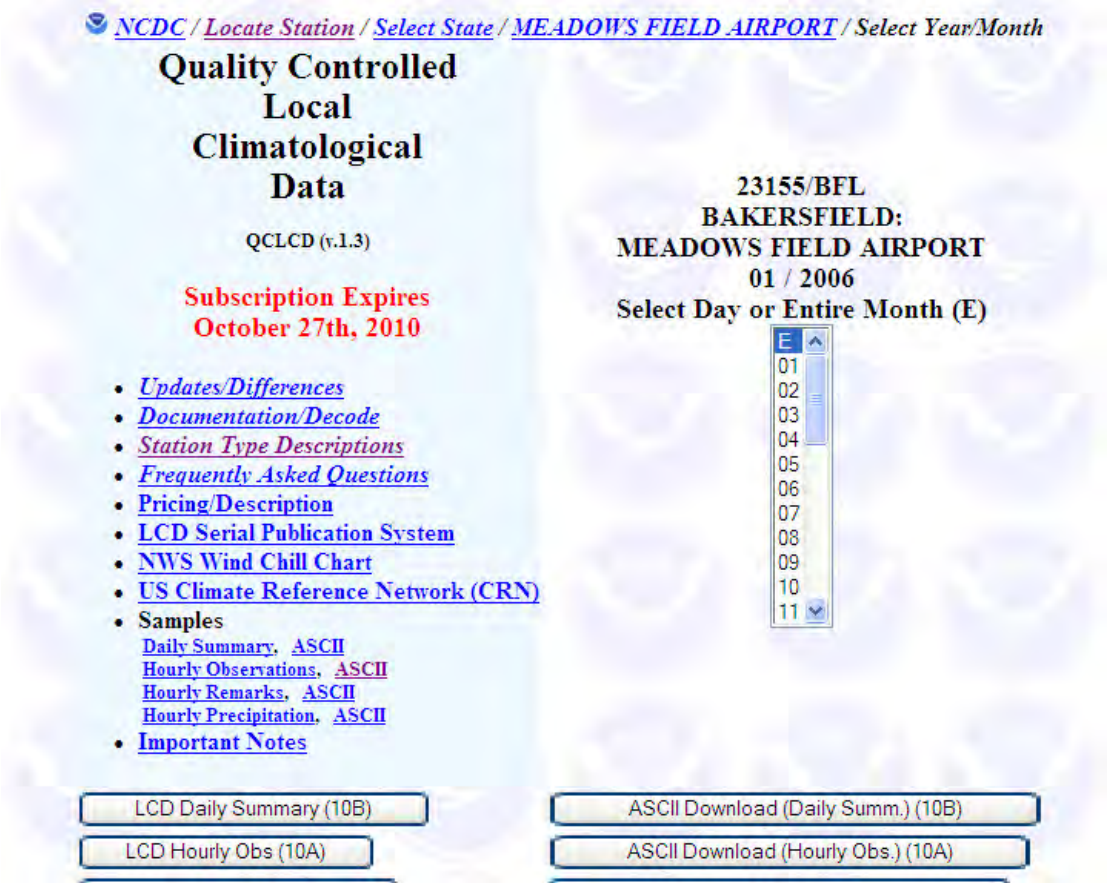
Review the list of available meteorological stations and select the station of Interest, then click “Continue”.

Step 7 – Select the meteorological data to open (12 files for each year)

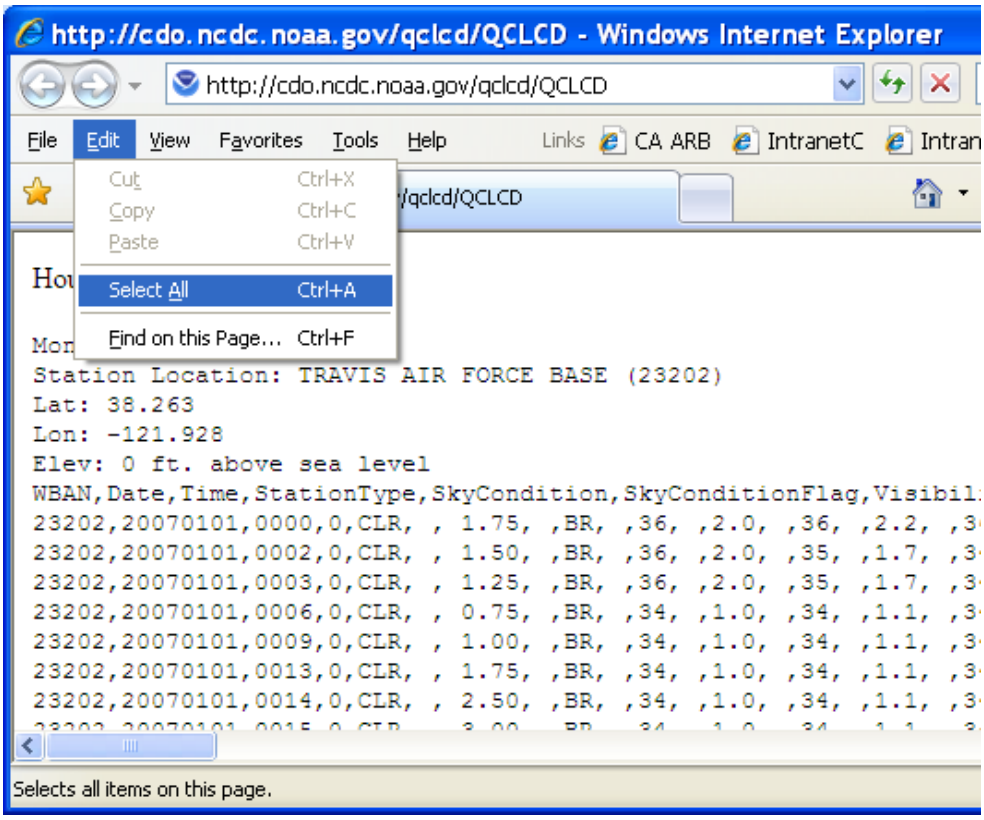
Please note: 1 year of meteorological data is broken into 12 files, one for each month.

From the list of available data select a file to open then click “Continue”

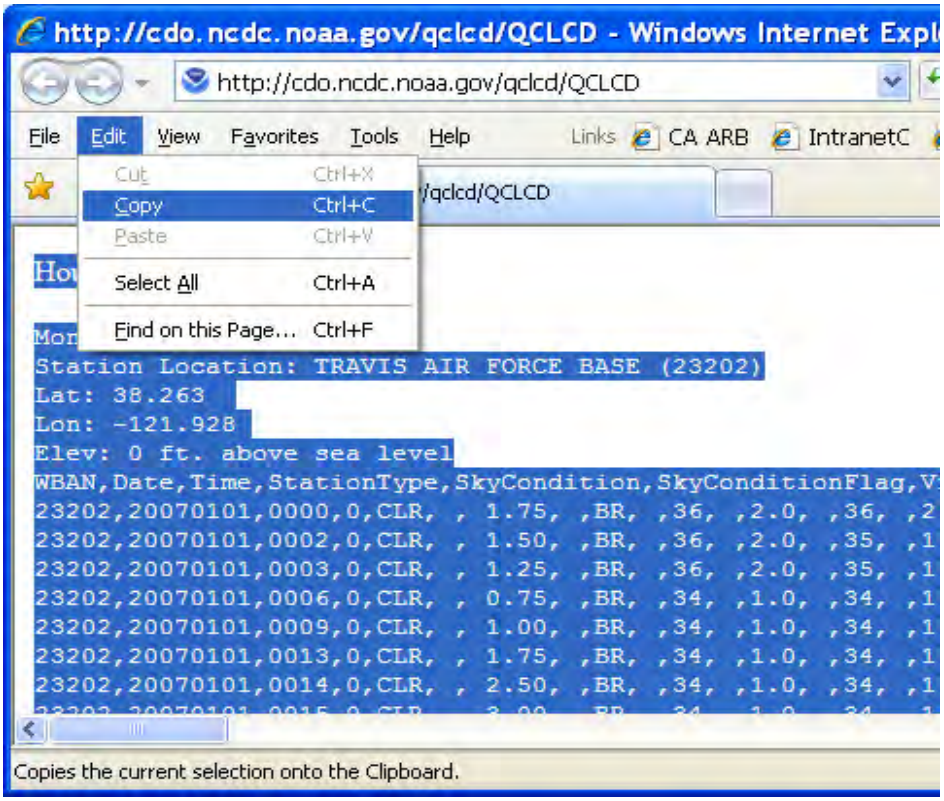
Step 8 – Select E (Entire month) then click on “ASCII Download (Hourly Obs) (10A)”. This will open a second browser window.



Step 9 – From the browser menu select EDIT --> Select All

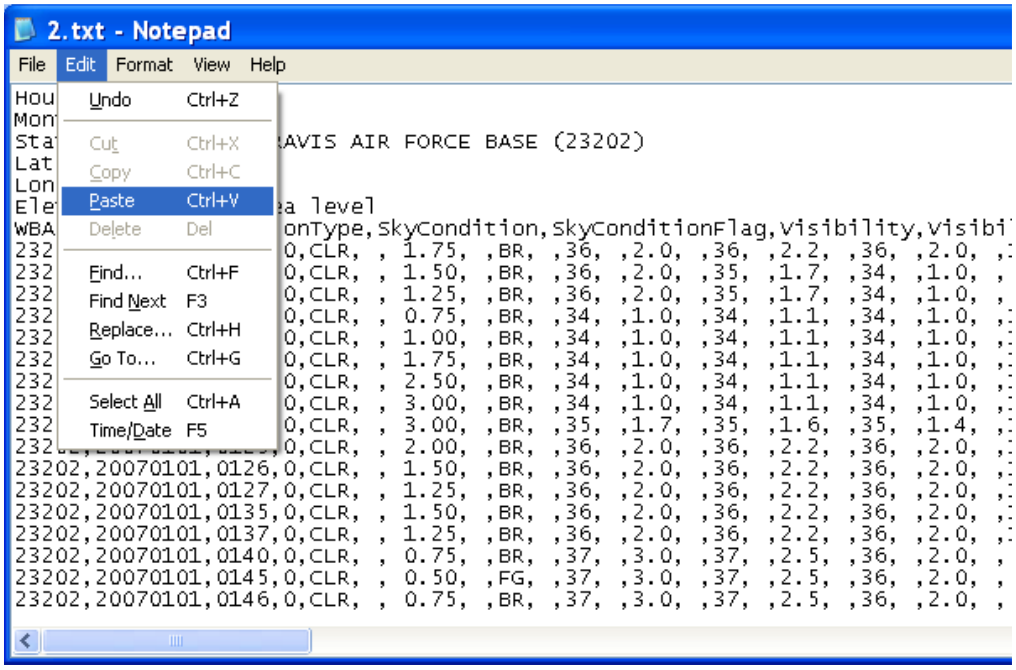


Step 10 – From the browser select EDIT --> COPY

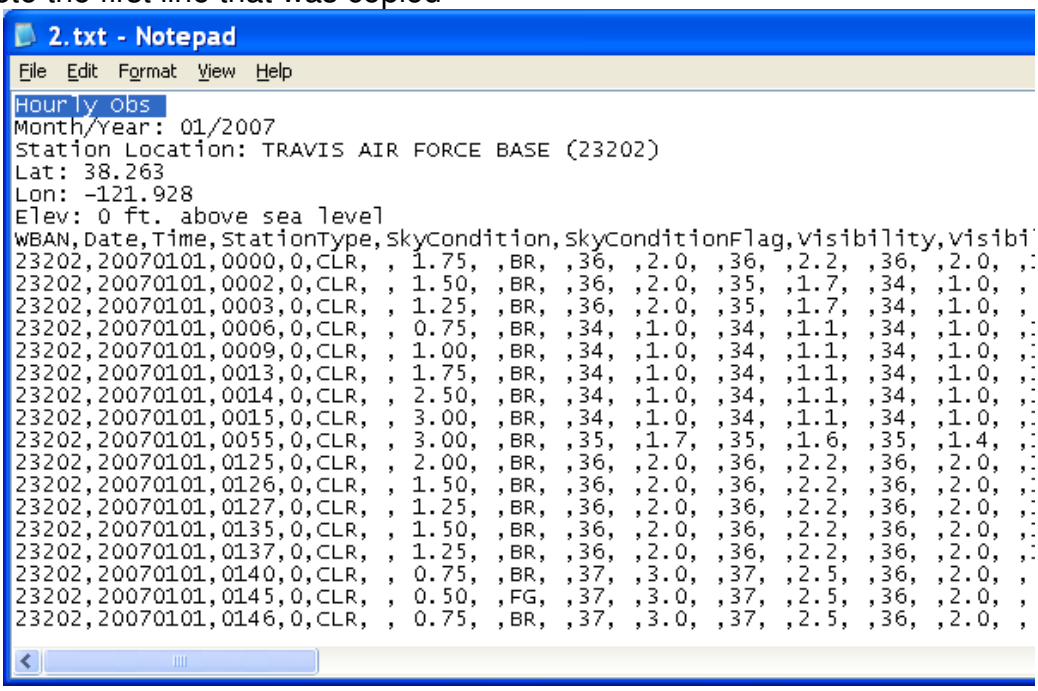


Please note: Steps 9 and 10 can be performed using the following quick keys
CTL + A = Select ALL and CTL + C = Copy

Step 11- Open a text editor like WORD PAD and select EDIT --> PASTE. If you are going to use the data in the section entitled "**<u>How to Process My Data</u>**" then it is recommended that you use the template files included on the CD. Copy the folder called "YEAR" and rename it to represent the year of the meteorological data being downloaded. Within this folder are 12 files numbered 1 thru 12, one for each month of the year. Open the corresponding file for the month being downloaded and paste the data.



Step 12 – Delete the first line that was copied



```
Hourly Obs
Month/Year: 01/2007
Station Location: TRAVIS AIR FORCE BASE (23202)
Lat: 38.263
Lon: -121.928
Elev: 0 ft. above sea level
WBAN,Date,Time,StationType,SkyCondition,SkyConditionFlag,Visibility,Visibi
23202,20070101,0000,0,CLR, , 1.75, ,BR, ,36, ,2.0, ,36, ,2.2, ,36, ,2.0, ,
23202,20070101,0002,0,CLR, , 1.50, ,BR, ,36, ,2.0, ,35, ,1.7, ,34, ,1.0, ,
23202,20070101,0003,0,CLR, , 1.25, ,BR, ,36, ,2.0, ,35, ,1.7, ,34, ,1.0, ,
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23202,20070101,0146,0,CLR, , 0.75, ,BR, ,37, ,3.0, ,37, ,2.5, ,36, ,2.0, ,
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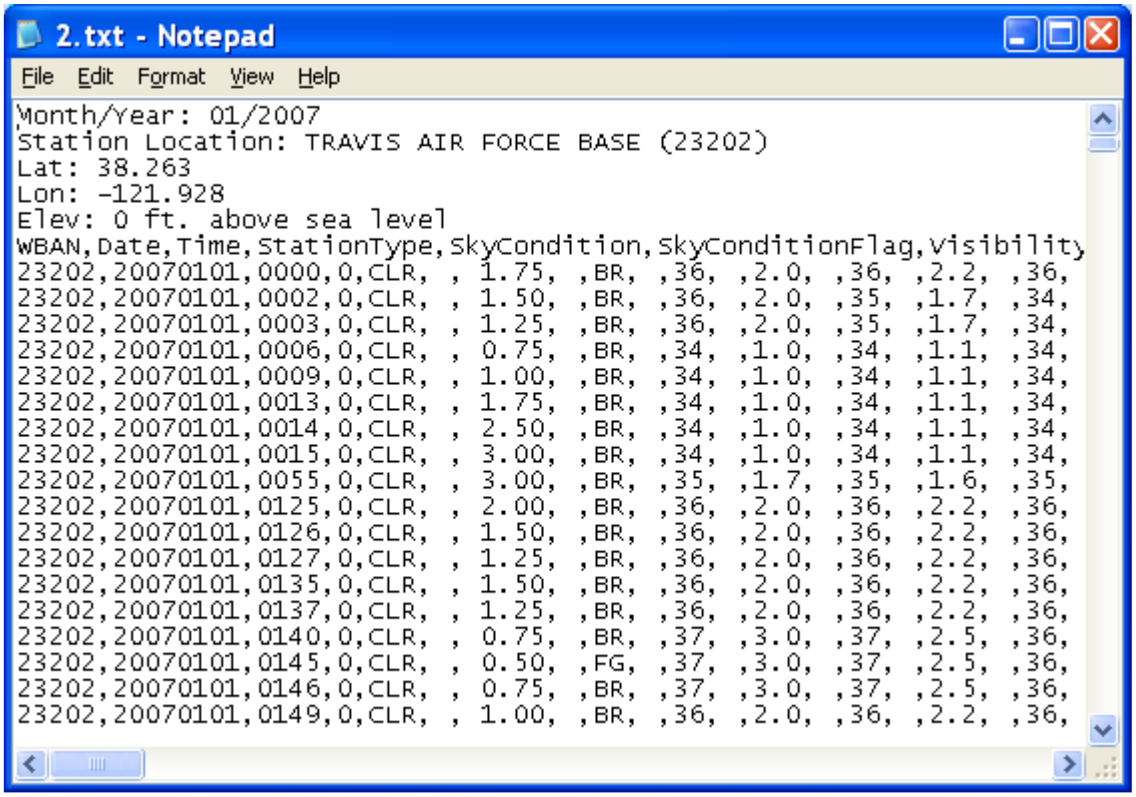
Highlight the first line as seen above and press the “Delete” key

Step 13 – The final file should look like below



```
Month/Year: 01/2007
Station Location: TRAVIS AIR FORCE BASE (23202)
Lat: 38.263
Lon: -121.928
Elev: 0 ft. above sea level
WBAN,Date,Time,StationType,SkyCondition,SkyConditionFlag,Visibility
23202,20070101,0000,0,CLR, , 1.75, ,BR, ,36, ,2.0, ,36, ,2.2, ,36,
23202,20070101,0002,0,CLR, , 1.50, ,BR, ,36, ,2.0, ,35, ,1.7, ,34,
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23202,20070101,0014,0,CLR, , 2.50, ,BR, ,34, ,1.0, ,34, ,1.1, ,34,
23202,20070101,0015,0,CLR, , 3.00, ,BR, ,34, ,1.0, ,34, ,1.1, ,34,
23202,20070101,0055,0,CLR, , 3.00, ,BR, ,35, ,1.7, ,35, ,1.6, ,35,
23202,20070101,0125,0,CLR, , 2.00, ,BR, ,36, ,2.0, ,36, ,2.2, ,36,
23202,20070101,0126,0,CLR, , 1.50, ,BR, ,36, ,2.0, ,36, ,2.2, ,36,
23202,20070101,0127,0,CLR, , 1.25, ,BR, ,36, ,2.0, ,36, ,2.2, ,36,
23202,20070101,0135,0,CLR, , 1.50, ,BR, ,36, ,2.0, ,36, ,2.2, ,36,
23202,20070101,0137,0,CLR, , 1.25, ,BR, ,36, ,2.0, ,36, ,2.2, ,36,
23202,20070101,0140,0,CLR, , 0.75, ,BR, ,37, ,3.0, ,37, ,2.5, ,36,
23202,20070101,0145,0,CLR, , 0.50, ,FG, ,37, ,3.0, ,37, ,2.5, ,36,
23202,20070101,0146,0,CLR, , 0.75, ,BR, ,37, ,3.0, ,37, ,2.5, ,36,
23202,20070101,0149,0,CLR, , 1.00, ,BR, ,36, ,2.0, ,36, ,2.2, ,36,
```

Step 14 – Save and Close the file. Additionally close the second browser window open in Step 8.

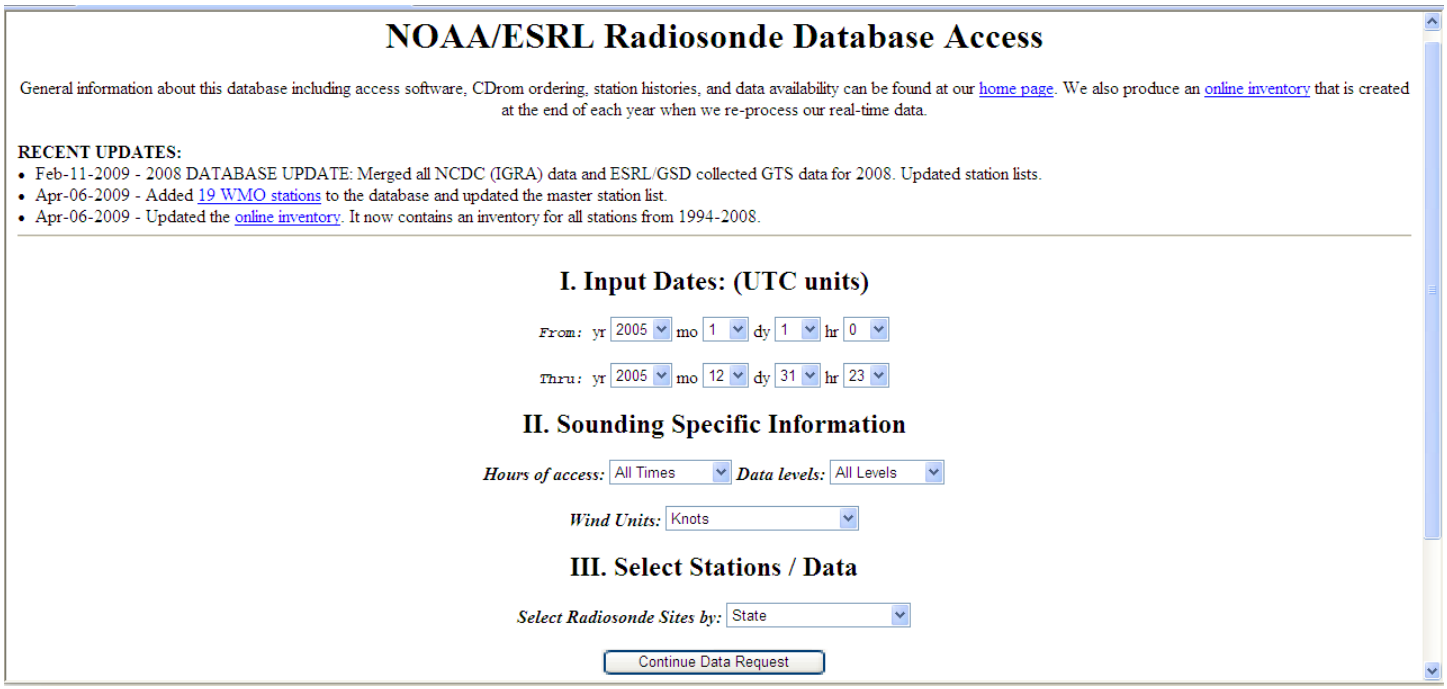
Step 15 – Click the “BACK” button on the browser and Repeat Steps 8 through 14 for each month that is to be downloaded.

Where’s My Upper-Air Data?

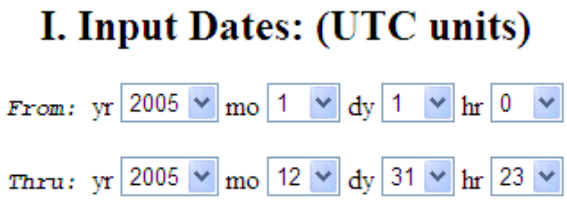
Now that the surface data has been downloaded, the matching upper-air data will also need to be retrieved. This data is freely available without restriction.

Where To Start:

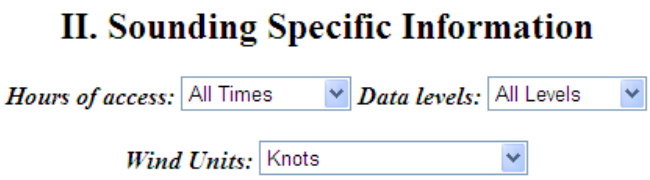
The upper-air data can be downloaded from http://esrl.noaa.gov/raobs/,



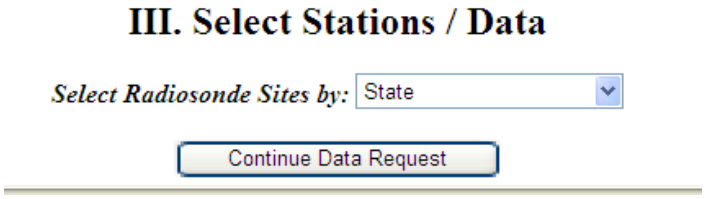
Step 1 – Select the time period to download. Set **From** inputs to: Year = (User define year), Month =1, Day = 1, and Hour=0 (midnight = morning). Set **Thru** inputs to: Year = (same as **From**), Month = 12, Day = 31, Hour = 23.



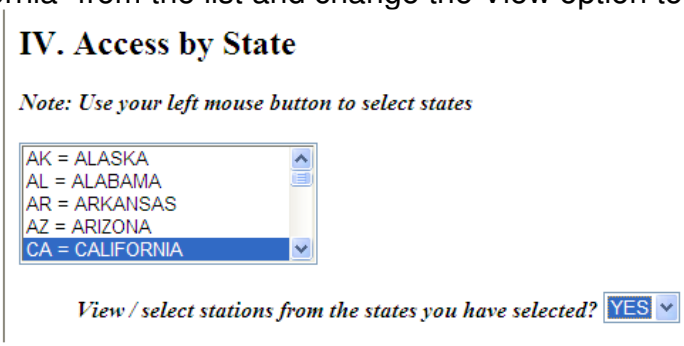
Step 2 – These options do not need to be altered.



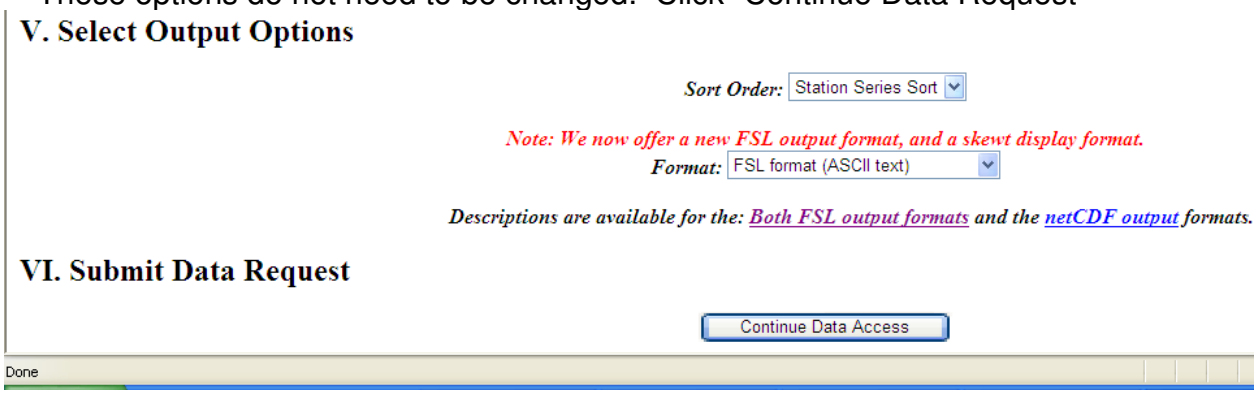
Step 3 – Change Radiosonde Site to “State” then click “Continue Data Request”



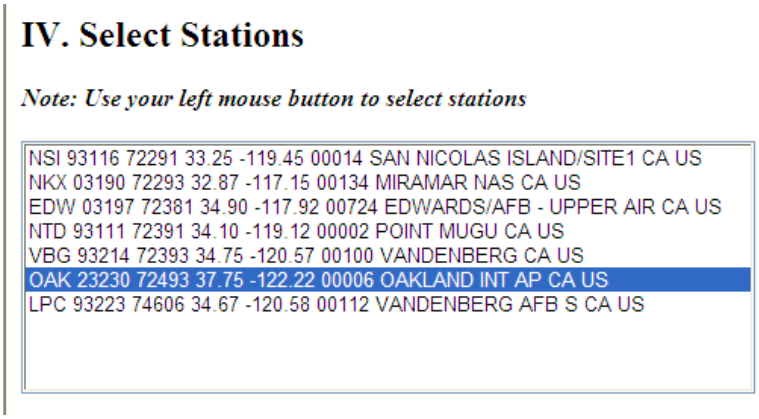
Step 4 – Select “CA-California” from the list and change the View option to “YES”



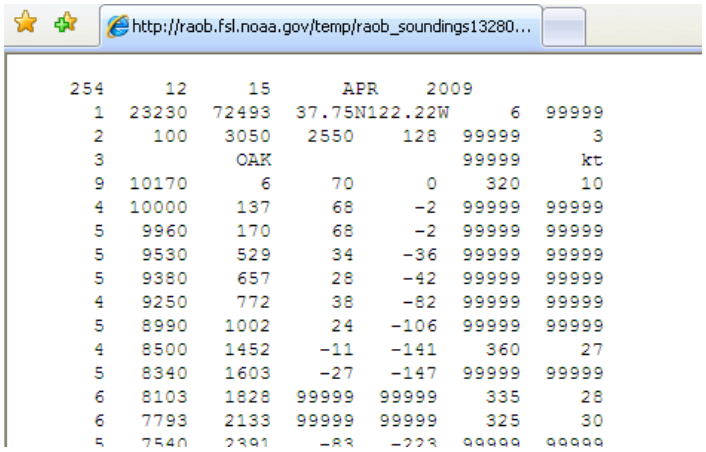
Step 5 – These options do not need to be changed. Click “Continue Data Request”



Step 6 – Select the station to download. The other options on this page do not need to be changed. Click “Get Radiosonde Data”



Step 7 – From the browser menu select EDIT → SELECT ALL then EDIT → COPY




```
254     12     15      APR    2009
  1  23230  72493  37.75N122.22W     6  99999
  2    100   3050   2550    128  99999      3
  3          OAK                 99999     kt
  9  10170      6     70      0    320     10
  4  10000    137     68     -2  99999  99999
  5   9960    170     68     -2  99999  99999
  5   9530    529     34    -36  99999  99999
  5   9380    657     28    -42  99999  99999
  4   9250    772     38    -82  99999  99999
  5   8990   1002     24   -106  99999  99999
  4   8500   1452    -11   -141    360     27
  5   8340   1603    -27   -147  99999  99999
  6   8103   1828  99999  99999    335     28
  6   7793   2133  99999  99999    325     30
  5   7540   2391    -83   -223  99999  99999
```

Step 8 – Paste the contents into a text file with a naming of XXXX.FSL. Where XXXX represents the year of the upper-air data. This will make it easier for AERMET to find the file.

Repeat steps 1 thru 8 for each year upper-air data set needed.

How to Process My Data

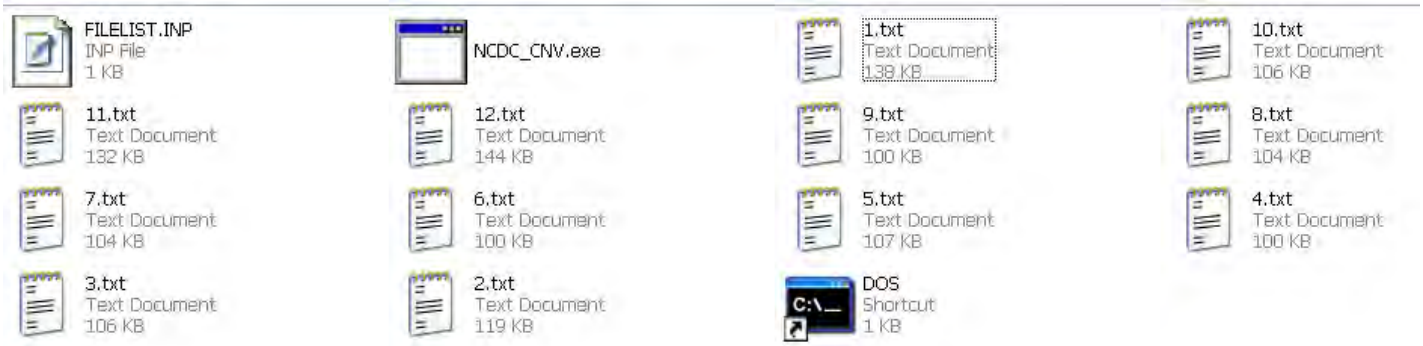
Now that you have downloaded the local meteorological data, it's time to QA/QC the data and convert it into a Samson file format. This will allow AERMET to read and process the data into an AERMOD ready meteorological file.

QA / QC and Converting Local Met Data into Samson Format:

EPA has several requirements for QA/QC meteorological data which are described in "Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models" by Dennis Atkinson and Russell F. Lee, 1992. (http://www.rflee.com/RFL_Pages/missdata.pdf). This document describes the EPA-recommended procedures for filling missing data for use in such air quality models as ISCST3 and AERMOD. It is identical to the text file "missdata.txt" available from the EPA SCRAM website, except that formatting has been applied to the text.

Mr. Russell F Lee has also developed a DOS based program that implements the above procedures as well as converts the data into a Samson file format, which AERMET can read. The NCDC_CNV (http://www.rflee.com/RFL_Pages/NCDC_CNV.zip) is a program which can convert the abbreviated hourly surface meteorological data provided online by NCDC in comma-separated ASCII format, and the Integrated Surface Hourly Weather Observations (ISHWO, aka ISH, ISHD) to the SAMSON format. The file is a zipped file containing the program, instructions, and a sample input file. This is being made available "as is" without charge by the developer, and may be freely distributed as long as the instruction file is included intact. The NCDC_CNV zip file has been included with this document for convenience.

For this part of the walk through we will be using the files located in the “SAMPLE YEAR” directory on the included CD, see below.



Please note: the FILELIST.INP and the NCDC_CNV.exe file will need to be located in the same directory as the files to be QA/QC in order to run properly.

The Input File Review:

For a detailed explanation of the NCDC_CNV input file please refer to the file entitled “INSTRUCTIONS_VERS_2008-09-17.txt” located on the provided CD

```
2008.SAM  2008-F.SAM 23155 -8 N 35 7 W 119 0 149 CSV NORMAL 54
Bakersfield
CA
1.txt
2.txt
3.txt
4.txt
5.txt
6.txt
7.txt
8.txt
9.txt
10.txt
11.txt
12.txt
```

For Help, press F1

The Input file can be broken down into three basic parts; Program Control Line, Station Name and State, and the Meteorological File(s) to Read.

Program Control Line:

```
2007.SAM  2007-F.SAM 23155 -8 N 35 7 W 119 0 149 CSV NORMAL 54
```

1 - No QA/QC Samson File
2 - Final QA/QC Samson File
3 - Station ID number
4 - Time Difference (GMT)
5 - Met Station Location
6 - Met Station Elevation
7 - Met File Format
8 – Included Station Pressure
9 – Normal sampling time

Detailed Item Description:

1) Filename of the output file converted to SAMSON format.
Missing hours are not filled in this file.
2) Name of output file with missing data filled per Atkinson & Lee.
3) Station ID (5-digit number). This number will appear in the output SAMSON file.
4) Time zone (EST = -5, CST = -6, MST = -7, PST = -8, etc.)
5a) 'N' or 'S' to indicate North or South latitude.
5b) Latitude--whole degrees portion.
5c) Latitude--minutes portion.
5d) 'E' or 'W' to indicate East or West longitude.
5e) Longitude--whole degrees portion.
5f) Longitude--minutes portion.
6) Elevation of station above mean sea level, in meters.
7) Type of input data:
CSV, csv: Comma-separated values from NCDC online store. This accommodates all known variants of the format, and will likely accommodate future ones as well.
8) NORMAL or SUBSLP. NORMAL gives the SAMSON format the station pressure.
SUBSLP substitutes sea level pressure for station pressure. CAUTION: Use SUBSLP only for stations fairly near sea level, when the station pressure is missing.
9) Code to identify minutes value(s) used for regular hourly (not special) data.
This is only used for space-delimited data (ABBRDS), but must always be present.

Station Name and State:

```
Bakersfield
CA
```

The City or Station name, up to 22 characters

State or province abbreviation, 2 characters

Meteorological File(s) to Read:

List of input files to be read and converted. These files will be concatenated in the order listed into the Samson output files noted in the Control Line.

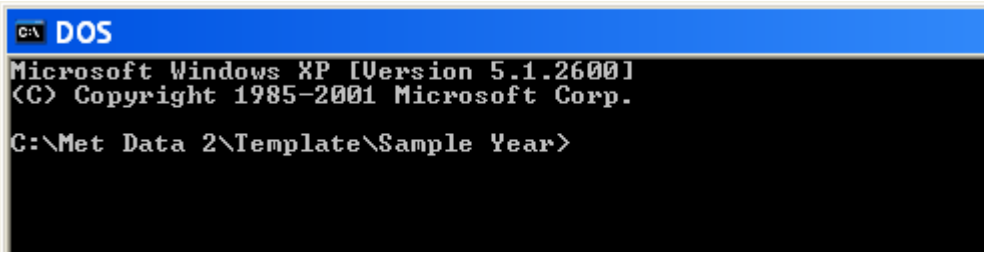
```
1.txt
2.txt
3.txt
4.txt
5.txt
6.txt
7.txt
8.txt
9.txt
10.txt
11.txt
12.txt
```

Local meteorological file downloaded from NCDC

Step 1 – Updating the Input File

For each year of meteorological data to be processed the Control Line should be adjusted to reflect the parameters of the station to be processed.

Step 2 – Open a DOS Window and go to the directory that contains the files to be processed.



Step 3 – Run the NCDC_CNV.exe program. By typing

NCDC_CNV filelist.inp

Then pressing Enter on the keyboard

```
DOS
Microsoft Windows XP [Version 5.1.2600]
(C) Copyright 1985-2001 Microsoft Corp.

C:\Met Data 2\Template\Sample Year>ncdc_cnv filelist.inp_
```

This will start the program. It should read each file listed in the INP file, one for each month of the year. Below is an example of the screen output after the program has run successfully.

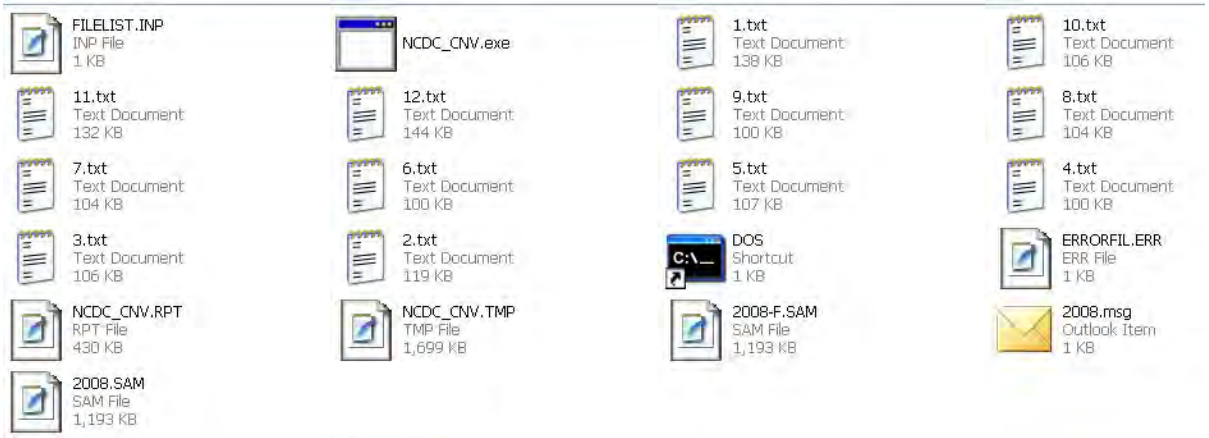
```
DOS
Microsoft Windows XP [Version 5.1.2600]
(C) Copyright 1985-2001 Microsoft Corp.

C:\Met Data 2\Template\Sample Year>ncdc_cnv filelist.inp
  Processing station: MEADOWS F; year          8 ; month:          1
  Processing station: MEADOWS F; year          8 ; month:          2
  Processing station: MEADOWS F; year          8 ; month:          3
  Processing station: MEADOWS F; year          8 ; month:          4
  Processing station: MEADOWS F; year          8 ; month:          5
  Processing station: MEADOWS F; year          8 ; month:          6
  Processing station: MEADOWS F; year          8 ; month:          7
  Processing station: MEADOWS F; year          8 ; month:          8
  Processing station: MEADOWS F; year          8 ; month:          9
  Processing station: MEADOWS F; year          8 ; month:         10
  Processing station: MEADOWS F; year          8 ; month:         11
  Processing station: MEADOWS F; year          8 ; month:         12

C:\Met Data 2\Template\Sample Year>
```

Station Name Year Month

Files Created by the NCDC_CNV Program:



List of Files Created:

2008.SAM – Downloaded meteorological data converted into Samson format
2008-F.SAM – The 2007.SAM file that has been QA/QC
2008.msg – Provides a list of the missing data that has been filled using EPA guidance
Errorfil.err – Provides a list of program errors, if any.
NCDC_CNV.RPT – Detailed list of each hour for each month that was read.
NCDC_CNV.TMP – Temporary file used when reading data from the 12 individual files before converting it into the Samson Format.

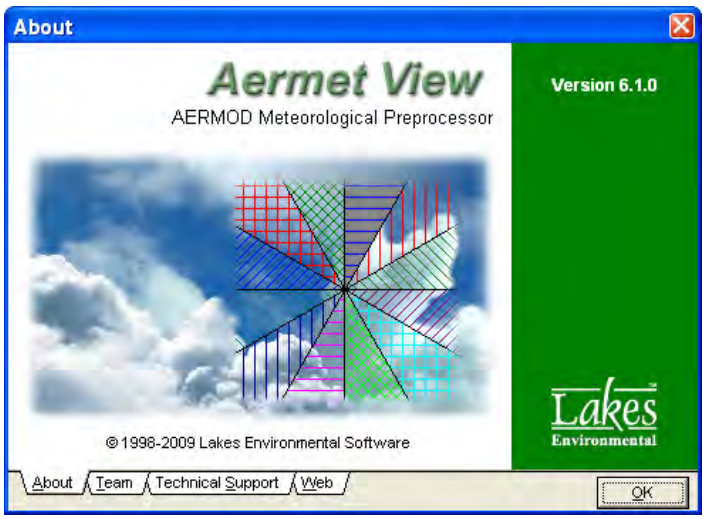
Step 4 – Close the DOS window by typing “Exit”

AERMET Processing:

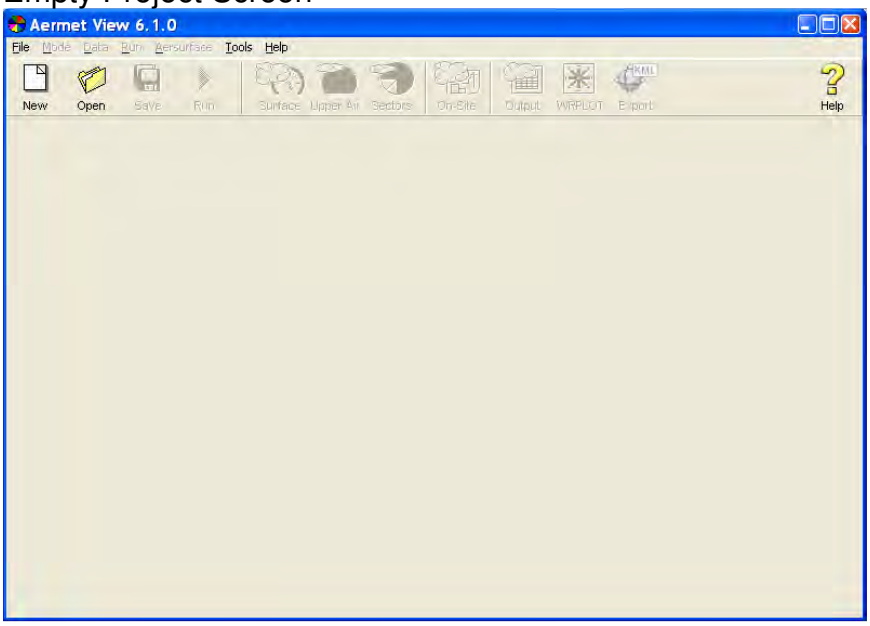
The final step in processing the meteorological data is to run AERMET with both the upper-air data and Samson file created in the previous section. For this part of the walk through we will be using the Lakes Environmental AERMET user interface.

Step 1 – Create a new AERMET project file using Lakes Environmental AERMET View.

On starting the AERMET View program the “ABOUT” screen will appear. Click the “OK” button to continue.

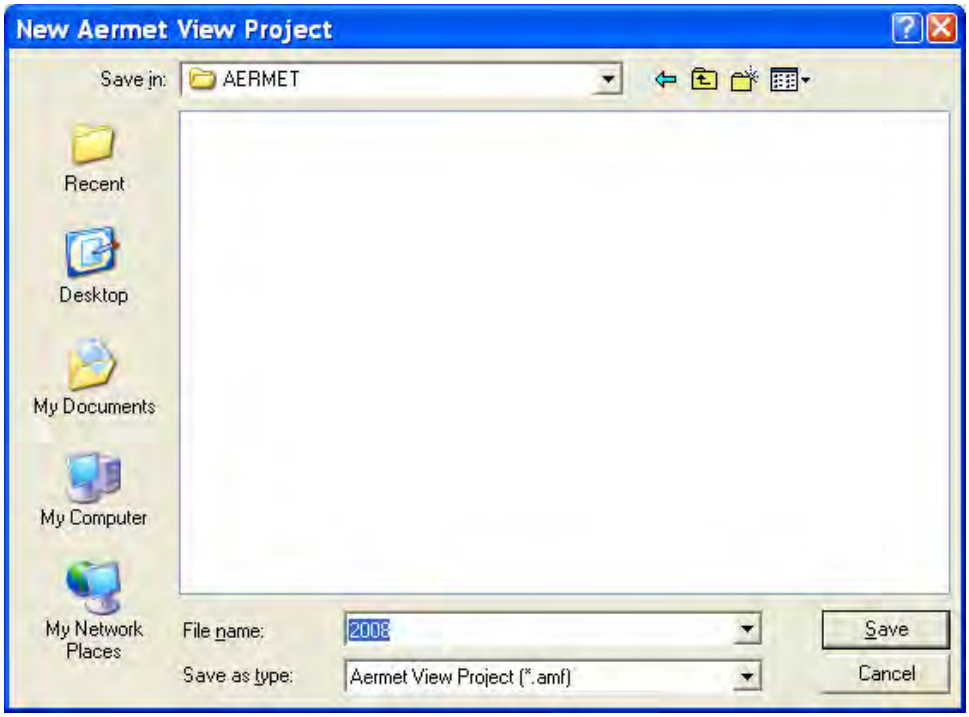


Empty Project Screen



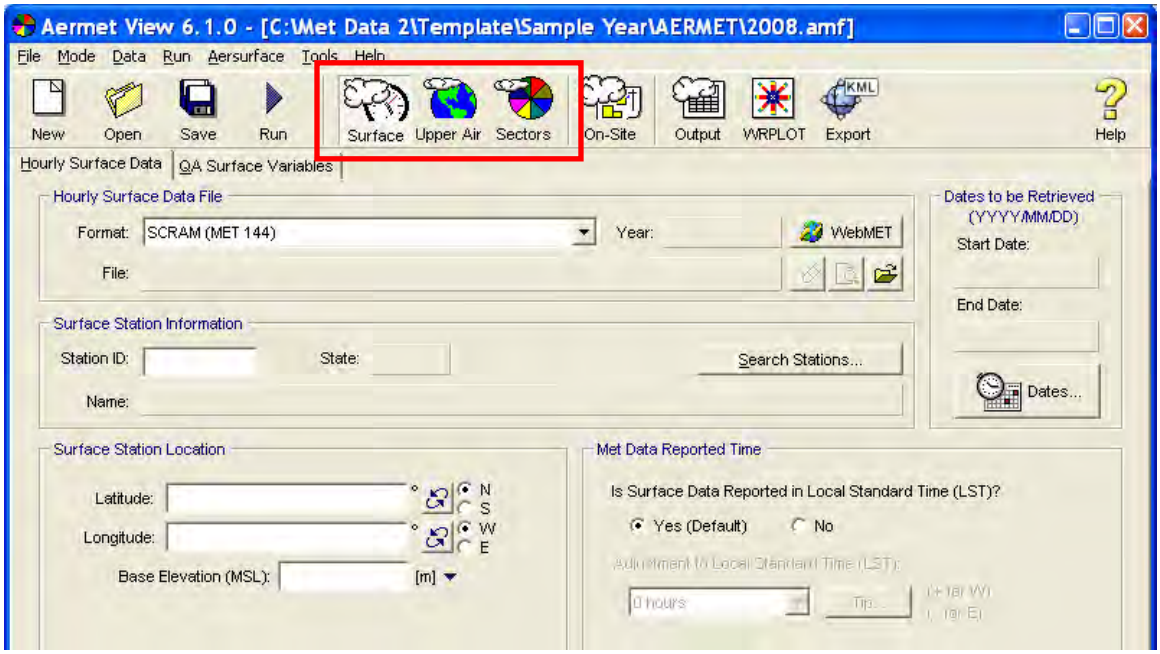
Click the “NEW” button or from the menu select File →New Project

On the “New Aermet View Project“ screen, enter a file name that will be used to store your inputs. It is recommended that you use the year for the meteorological data as the name for the project. It is also recommended that you create a separate directory for the other files downloaded and generated in the previous sections. Once the file name has been entered click “SAVE”.



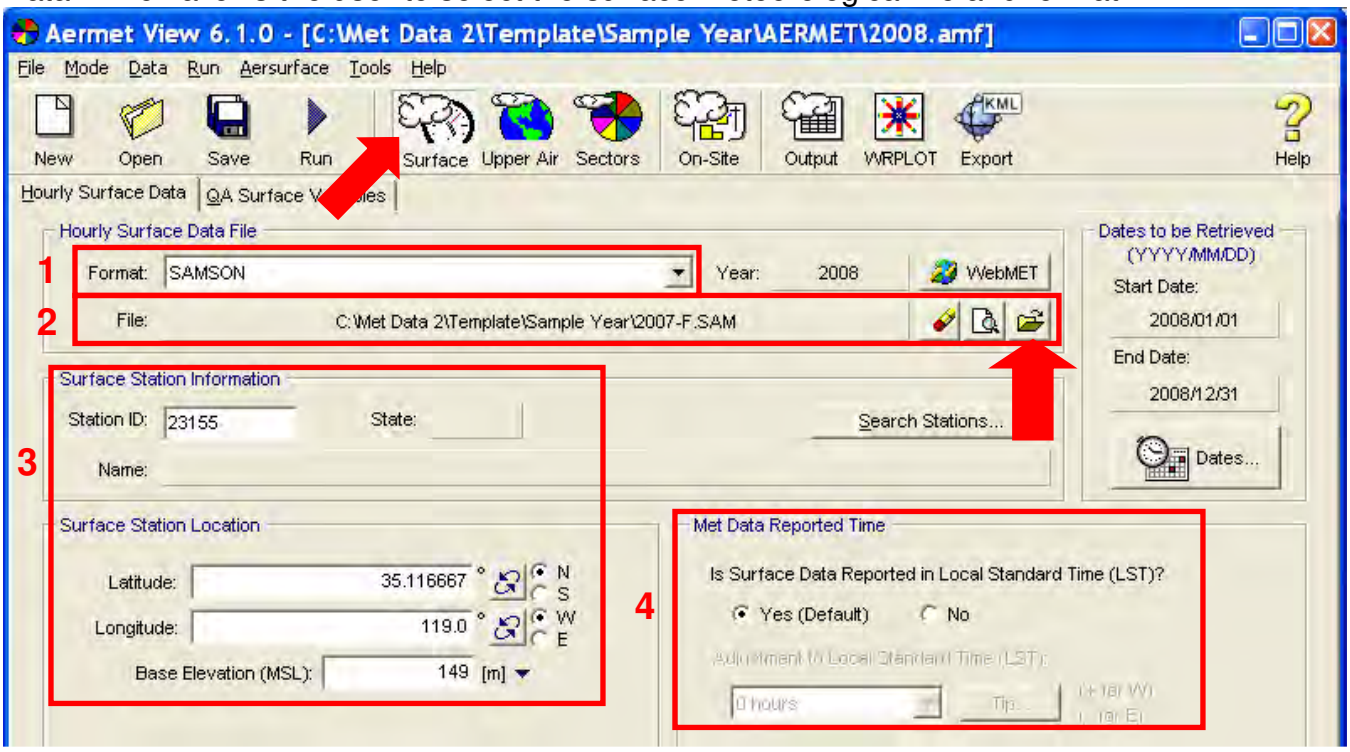
AERMET Input Screen

For this part of the walk through we will be dealing with three main screens Surface, Upper Air, and Sectors.



Surface Screen

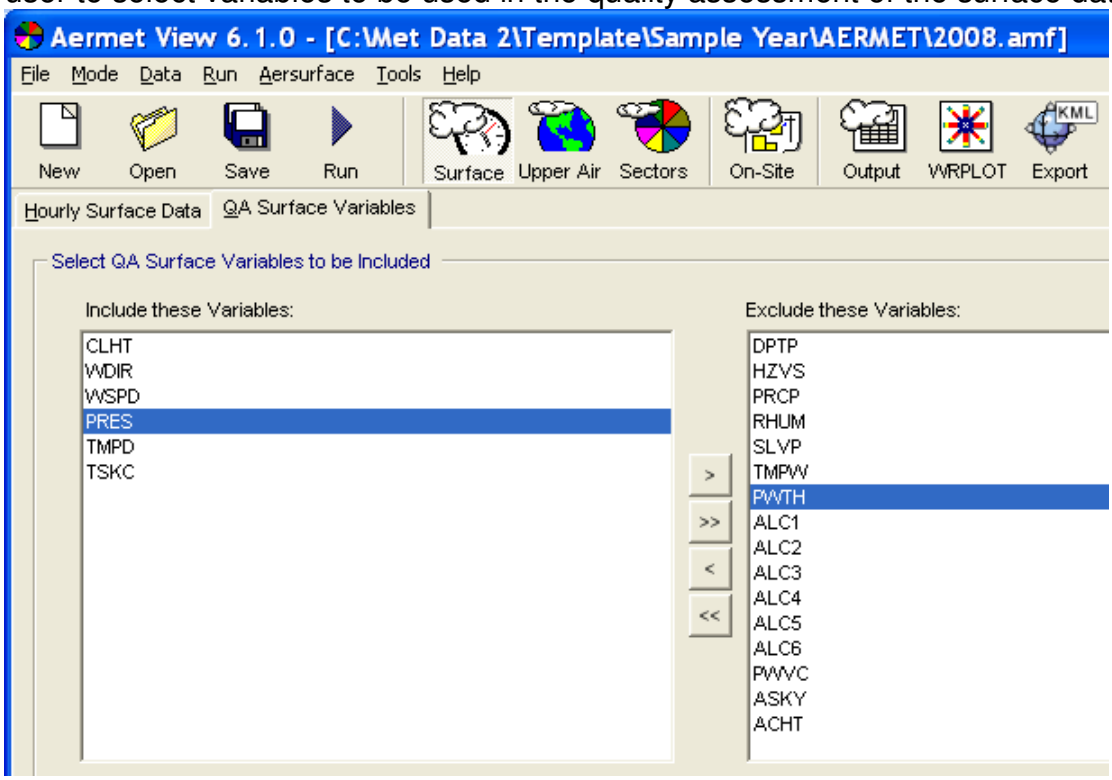
The Surface screen has two tabs that need to be reviewed. The first tab is the "Hourly Surface Data" which allows the user to select the surface meteorological file and format.



Screen Details:

Detail #	Description
1	From the pull down select the "SAMSON" option.
2	Using the Open File button navigate to, and select the Samson file created by the NCDC_CNV program in the previous section.
3	The data in this section will be entered automatically after the Samson file is selected.
4	Insure that the "Yes (Default)" option is selected.

The Second tab on the Surface Screen is the “QA Surface Variable” tab. This tab allows the user to select variables to be used in the quality assessment of the surface data.



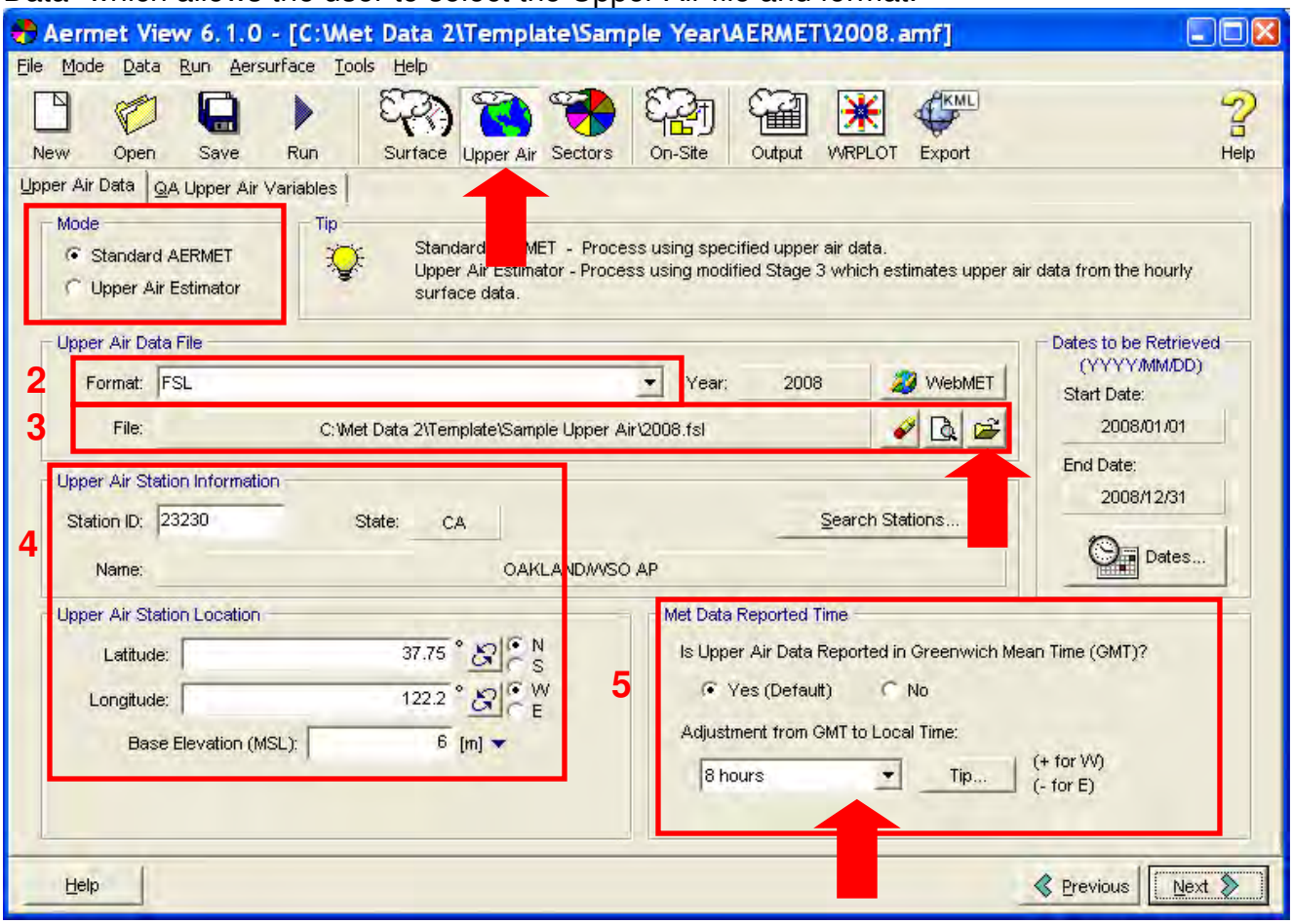
Detailed descriptions of the available variables.

Hourly Surface QA Variables

Variable Name	Description	Units	Boundary Type	Missing Indicator	Lower Bound	Upper Bound
CLHT	Ceiling height	kilometers * 10	Include (<=)	999	0	300
DPTP	Dew-point temperature	deg C * 10	Exclude (<)	999	-650	350
HZVS	Horizontal visibility	kilometers * 10	Include (<=)	99999	0	1640
PRCP	Precipitation amount	millimeters * 1000	Include (<=)	-9	0	25400
PRES	Station pressure	millibars * 10	Exclude (<)	99999	9000	10999
RHUM	Relative humidity	whole percent	Include (<=)	999	0	100
SLVP	Sea level pressure	millibars * 10	Exclude (<)	99999	9000	10999
TMPD	Dry bulb temperature	deg C * 10	Exclude (<)	999	-300	360
TMPW	Wet bulb temperature	deg C * 10	Exclude (<)	999	-650	350
TSKC	Total // opaque sky cover	tenths // tenths	Include (<=)	9999	0	1010
WDIR	Wind direction	tens of degrees	Include (<=)	999	0	36
PWTH	Present weather		Include (<=)	9999	0	9800
WSPD	Wind speed	meters/second * 10	Include (<=)	999	0	500
ALC1	Sky cond // height, level 1	code // hundredths ft	Include (<=)	9999	0	7300
ALC2	Sky cond // height, level 2	code // hundredths ft	Include (<=)	9999	0	7300
ALC3	Sky cond // height, level 3	code // hundredths ft	Include (<=)	9999	0	7300
ALC4	Sky cond // height, level 4	code // hundredths ft	Include (<=)	9999	0	7850
ALC5	Sky cond // height, level 5	code // hundredths ft	Include (<=)	9999	0	7850
ALC6	Sky cond // height, level 6	code // hundredths ft	Include (<=)	9999	0	7850
PWVC	Present weather (vicinity)		Include (<=)	9999	0	9800
ASKY	ASOS Sky condition	tenths	Include (<=)	99	0	10
ACHT	ASOS Ceiling	kilometers * 10	Include (<=)	999	0	888

Upper AIR Screen:

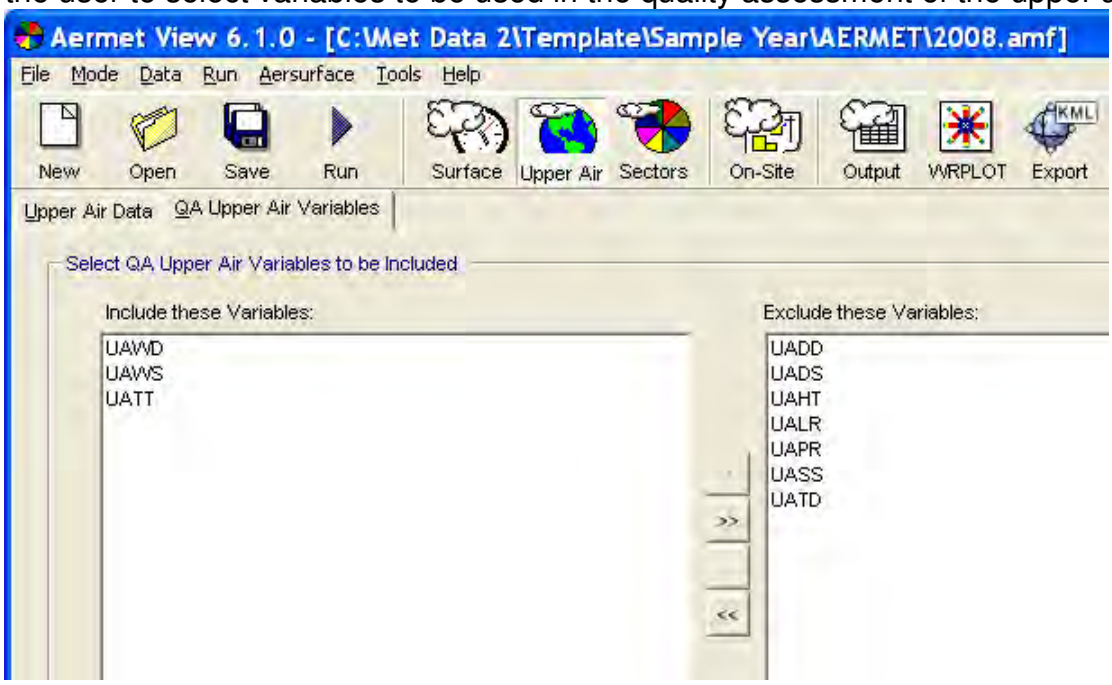
The Upper Air screen has two tabs that need to be reviewed. The first tab is the "Upper Air Data" which allows the user to select the Upper Air file and format.



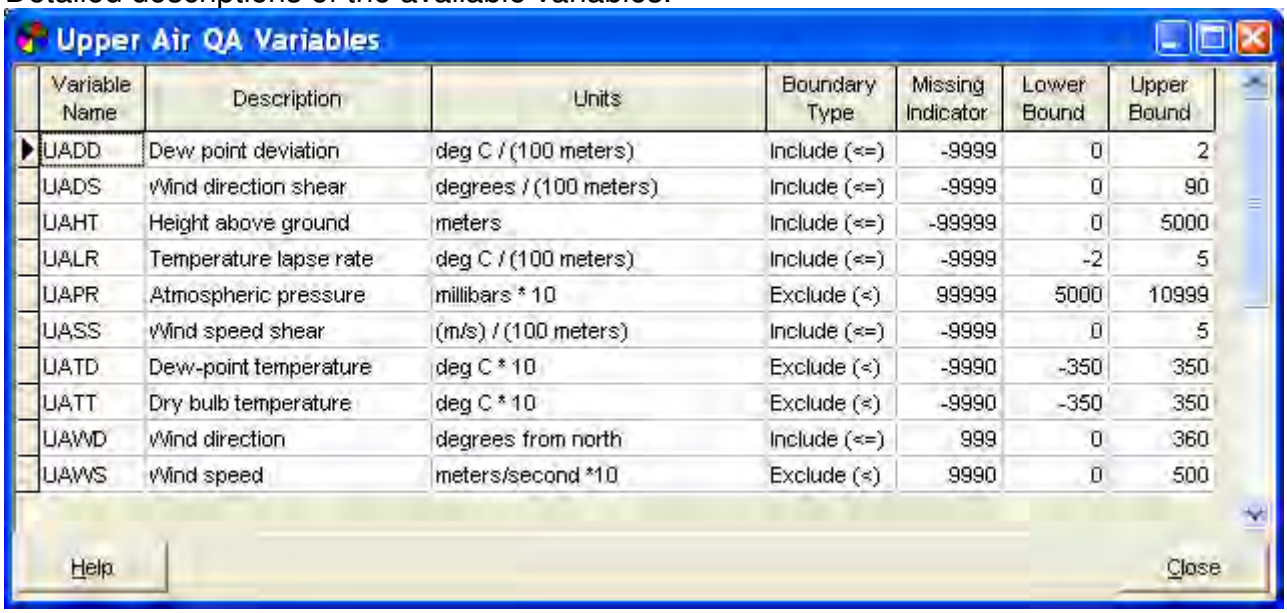
Upper Air Details:

Detail #	Description
1	Select "Standard AERMET".
2	From the pull down select the "FSL" option.
3	Using the Open File button navigate to, and select the FSL file (upper air data) that was previously downloaded.
4	The data in this section will be entered automatically after the FSL file is selected.
5A	Insure that the "Yes (Default)" option is selected. Upper air data is reported in GMT (Greenwich Mean Time) and need to be adjusted to local time.
5B	In the pull down select the "8 hours" option. California is 8 hours behind GMT. This will adjust the upper air data to match the surface data being processed (LST- Local Standard Time).

The Second tab on the Upper Air Screen is the “QA Upper Air Variable” tab. This tab allows the user to select variables to be used in the quality assessment of the upper air data.



Detailed descriptions of the available variables.



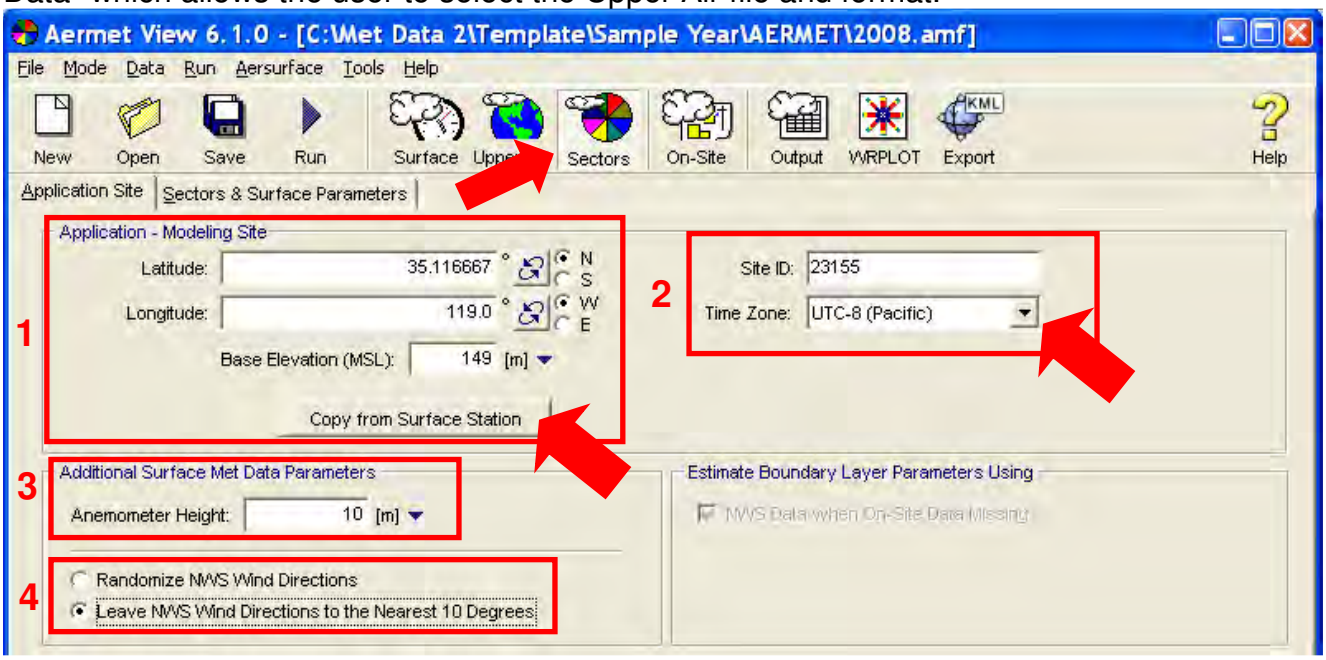
Upper Air QA Variables

Variable Name	Description	Units	Boundary Type	Missing Indicator	Lower Bound	Upper Bound
UADD	Dew point deviation	deg C / (100 meters)	Include (<=)	-9999	0	2
UADS	Wind direction shear	degrees / (100 meters)	Include (<=)	-9999	0	90
UAHT	Height above ground	meters	Include (<=)	-99999	0	5000
UALR	Temperature lapse rate	deg C / (100 meters)	Include (<=)	-9999	-2	5
UAPR	Atmospheric pressure	millibars * 10	Exclude (<)	99999	5000	10999
UASS	Wind speed shear	(m/s) / (100 meters)	Include (<=)	-9999	0	5
UATD	Dew-point temperature	deg C * 10	Exclude (<)	-9990	-350	350
UATT	Dry bulb temperature	deg C * 10	Exclude (<)	-9990	-350	350
UAWD	Wind direction	degrees from north	Include (<=)	999	0	360
UAWS	Wind speed	meters/second *10	Exclude (<)	9990	0	500

Help Close

Sectors Screen:

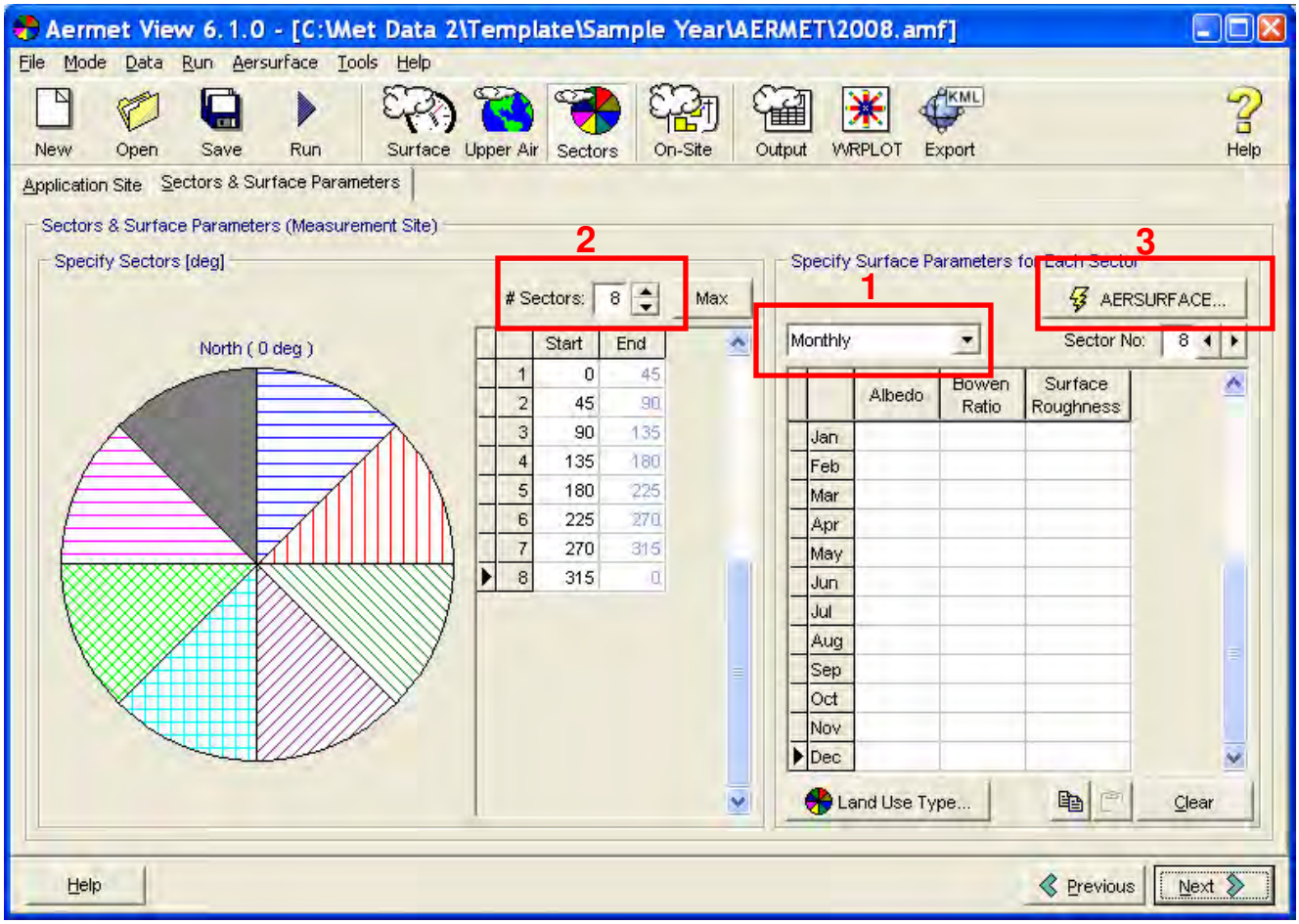
The Sectors screen has two tabs that need to be reviewed. The first tab is the "Upper Air Data" which allows the user to select the Upper Air file and format.



Sectors Details:

Detail #	Description
1	Click the "Copy From Surface Station". This information will be used to determine the Bowen Ratio, Albedo, and Surface roughness parameters on the second tab. Current EPA guidance suggests that the sector parameters be based on the location where the surface meteorological data was collected.
2A	Ensure that the Site ID field contains the surface station ID found on the "Hourly Surface Data" tab under the Surface screen.
2B	Ensure that the Tome Zone field contains the appropriate value. For California it should read "UTC–8 (Pacific)". UTC (coordinated universal time) is basically the 20th century GMT better know as the atomic clock.
3	The anemometers at ASOS station are typically set at 10 meters.
4	**Randomize NWS Wind Directions:** Select this option to randomize the NWS wind directions in order to avoid a bias toward the cardinal compass points (N, S, E, and W). The wind directions are randomized for each 10 degree sector to one degree increments. A bias would occur for the un-randomized wind directions because three 10-degree sectors would contribute to the N, S, E, and W sector statistics (e.g., 350, 360 and 10 degrees for the north sector), while only two 10-degree sectors would contribute to the other 22.5 degree sectors. **Leave NWS Wind Directions to the Nearest 10 Degrees:** This is the default option and reports the NWS wind directions to the nearest 10 deg. For example, a direction of 164 deg would be reported as 160. **<u>Please Note:</u>** this value should be set to Randomize NWS Wind Direction as required by EPA

The Second tab on the Sectors Screen is the “Sector & Surface Parameters” tab. This tab allows the user to enter surface parameters for sectors surrounding the meteorological station. EPA recommends that a 1 km radius be used to develop surface roughness parameters per sector and a 10 km radius be used to develop the Albedo and Bowen Ratio. Therefore it is recommended that AERSURFACE be used. The latest version of AERSUFACE incorporates the above recommendations.

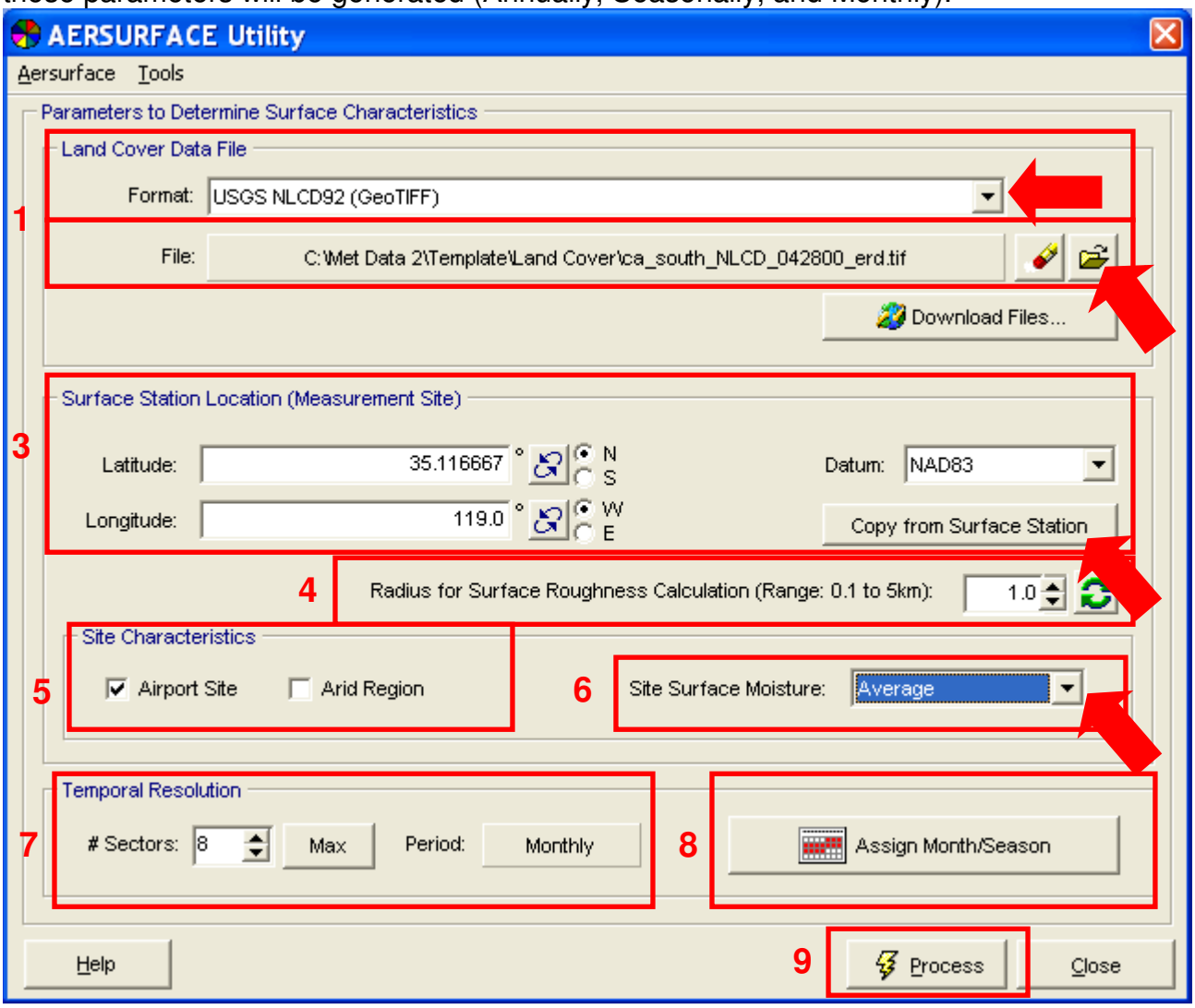


Sectors Details:

Detail #	Description
1	It is recommended that the surface parameters be based on a monthly basis.
2	It is recommended that the “# Sectors” field not be set to a value less than eight sectors.
3	Click on the AERSURFACE button to import surface parameters using land cover data. Land cover data is included on the CD for all of California and is located in a folder call “Land Cover”.

AERSURFACE Utility Screen:

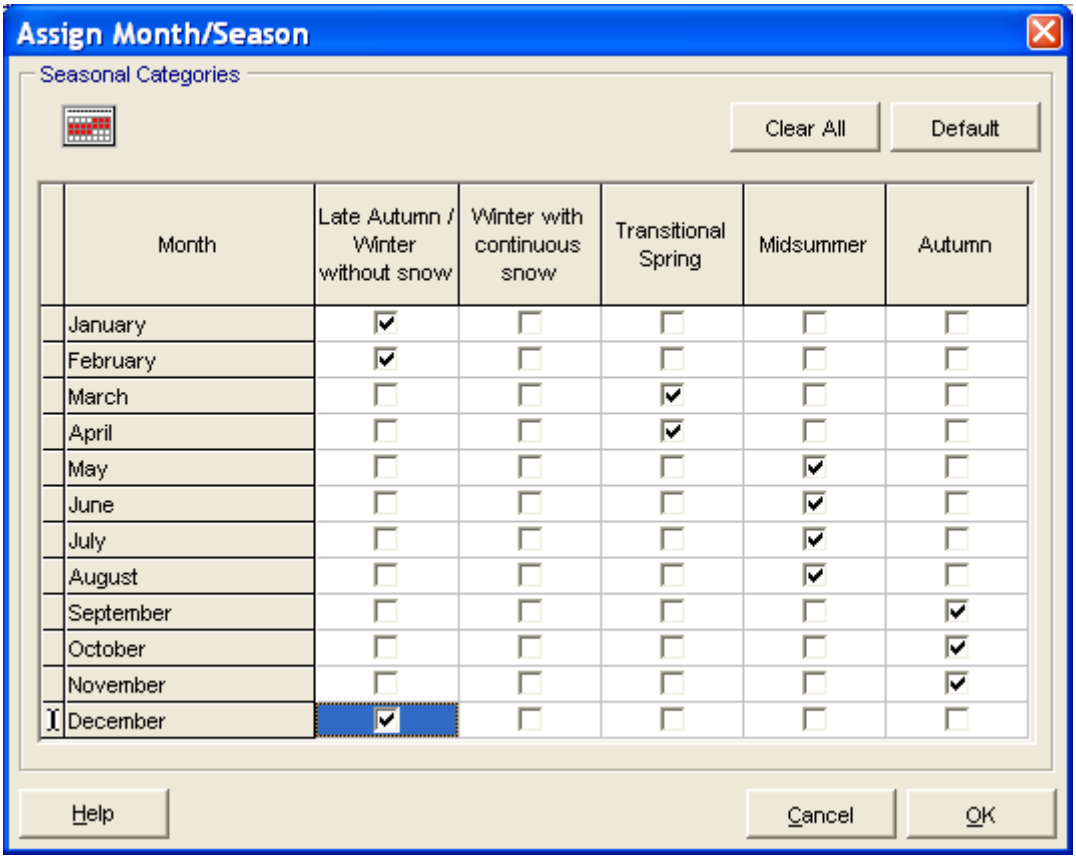
The AERSURFACE program is used to read land cover data contained in the Tiff files, which are included, using EPA guidance discussed above. It also allows the user to determine how those parameters will be generated (Annually, Seasonally, and Monthly).



Sectors Details:

Detail #	Description
1	From the pull down select "USGS NLCD92 (GEOTII)"
2	Using the Open File button navigate to, and select the Tiff file to be used to determine the site specific surface parameters for this project.
3	EPA guidance is to use the location of the monitoring site to determine surface parameters. Therefore, click the "Copy from Surface Station" button to copy the location information from the Surface screen.
4	As discussed above, EPA guidance as of Jan 9, 2008 is to us a 1km radius around the surface station to determine surface roughness.
5	Most ASOS sites are located at an airport. AERSURFACE will use surface characteristics that reflect an area more dominated by transportation land cover.
6	Project surface moisture conditions compared to a 30 year average ○ **Wet** if precipitation is in the upper 30th-percentile

Detail #	Description
	○ **Dry** if precipitation is in the lower 30th-percentile ○ **Average** if precipitation is in the middle 40th-percentile. The monthly and annual 30 year averages (1971 – 2000) are located in the LAND Cover folder on the CD.
7	This information comes from the previous screen and should not be altered.
8	If you are calculating **Annually** or **Monthly**, you have the option to assign the months of the year to seasons other than the default, see screen shot below. AERSURFACE will use the surface parameters based on the month vs. the season allocated on this screen.
9	To start AERSURFACE running Click the "Process" button. AERSURFACE will access the Tiff file for the location selected and derive the necessary parameters based on the month/season allocation determined by the user.



Land Cover Data:

Spatial Domains for Land Cover Files:

<u>California – North (ca_north_NLCD_042800_erd.tif)</u>

Bounding Coordinates:

West Bounding Coordinate: -125.091
East Bounding Coordinate: -118.088
North Bounding Coordinate: 41.826
South Bounding Coordinate: 37.660

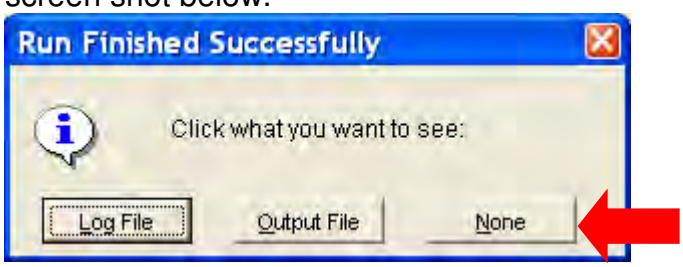
<u>California – South (ca_south_NLCD_042800_erd.tif)</u>

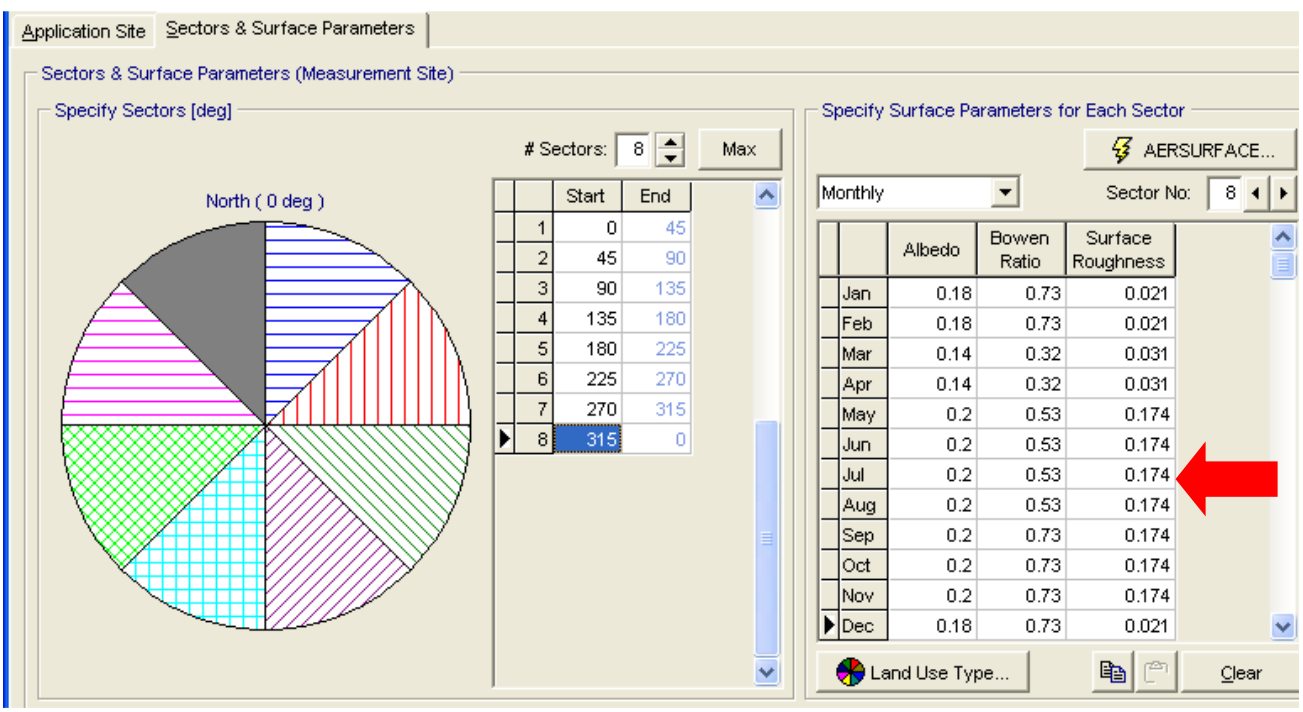
Bounding Coordinates:

West Bounding Coordinate: -123.029
East Bounding Coordinate: -113.800
North Bounding Coordinate: 36.651
South Bounding Coordinate: 32.858

Surface Parameters Have Been Derived:

Once AERSURFACE completes running the user should see the following screen and the parameters on the "Sectors & Surface Parameters" tabs should be filled in, see the second screen shot below.



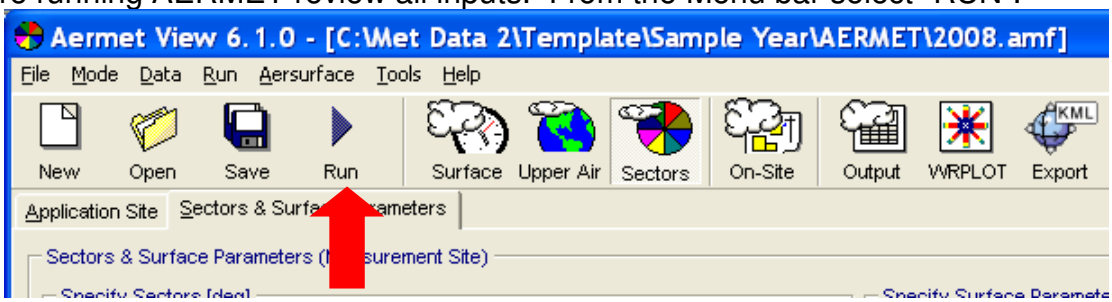


Are We There Yet?

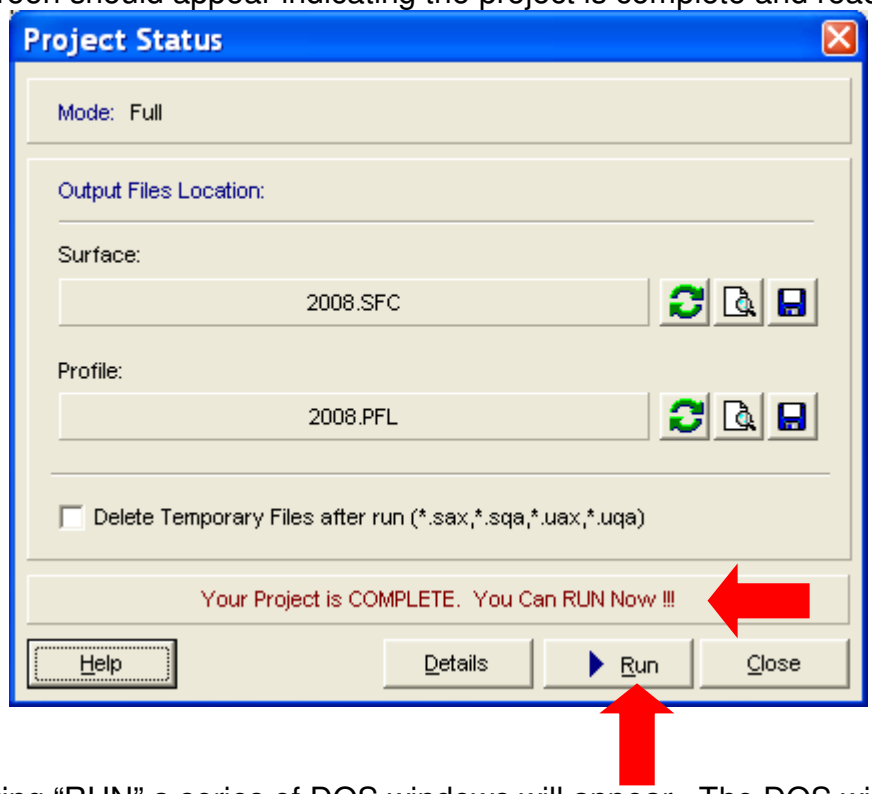
We are almost done. There are two final steps to completing the process. The first is to run AERMET and generate the Surface and Profile data files for AERMOD.

Running AERMET

Before running AERMET review all inputs. From the Menu bar select "RUN".



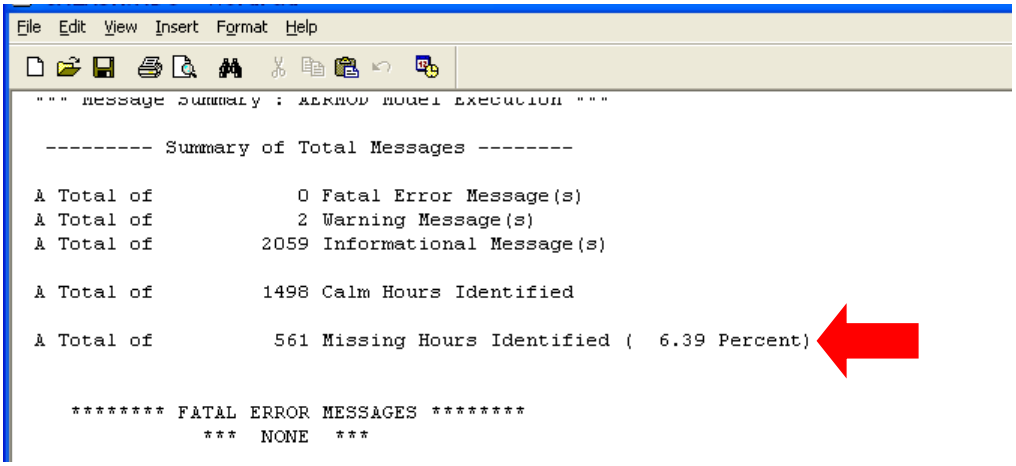
The following screen should appear indicating the project is complete and ready to run.



After clicking "RUN" a series of DOS windows will appear. The DOS windows represent the three stages OF THE AERMET process. The following screen should appear once the process is completed, allowing the user to view the new surface and profile files generated.

You are **DONE**. Close the AERMET program.

The Final Step is to run AERMOD and ensure that the number of missing hours is not greater than 10 percent. If your AERMOD run indicates that you have more than 10 percent missing hours, the data should not be used for regulatory purposes. An Air District can decide that this data is acceptable on a case by case basis.



Attachment C

CAPCOA, Modeling Compliance of the Federal 1-Hour NO2 NAAQS,

Appendix C, In-Stack NO2/NOX Ratios, October 2011

Recommend In-stack NO2/NOx Ratios				
Refer #	**Fuel**	**Equipment Category (Controls)**	**Range of Ratios (%)**	**Recommended Ratio (%)**
Boilers				
1	**NG**	Default	10	10
2		6.6 MMBtu/Hr (Force Draft)*[L]	0.0 – 2.90	1.58**
2		7.6 MMBtu/Hr (SCR / FGR)*	3.45 – 15.79	9.65**
2		11.4 MMBtu/Hr (Force Draft)*[L]	1.81 – 3.51	2.68**
Compressor IC Engines				
1	**NG**	Default	60	60
2a		225 BHP IGN Timing BTC 17***	11.61 – 11.86	11.76**
2a		350 BHP IGN Timing BTC 18***	4.37 – 4.83	4.66**
2a		550 BHP IGN Timing BTC 20***	0.93 – 2.98	1.96**
2a		625 BHP IGN Timing BTC 10***	10.97 – 11.96	11.6**
2a		773 BHP IGN Timing BTC 9***	58.04 – 58.54	58.3**
2a		773 BHP IGN Timing BTC 20***	72.65 – 73.42	73.12**
2a		880 BHP IGN Timing BTC 8***	9.79 – 14.14	11.93**
2a		880 BHP IGN Timing BTC 15***	0.7 – 8.28	2.52**
2a		1500 BHP IGN Timing BTC 12***	10.32 – 12.03	11.47**
2a		1500 BHP IGN Timing BTC 6.5***	18.42 – 21.33	19.97**
2a		4000 BHP IGN Timing BTC 5***	22.36 – 25.69	23.82**
2a	**Waste Gas (Field Gas)**	880 BHP IGN Timing BTC 20***	1.77 – 6.10	3.86**
2a		1000 BHP***	0.40 – 0.81	0.64**
Dryer				
	NG	20 MMBTU/Hr (Milk -Tower Dryer)*	3.85 – 11.11	6.88**
Glass Furnace				
2	**NG**	**Glass Furnace**	2.45 – 11.59	4.32**
Heaters				
2	**NG / Refinery Gas**	14.1 MMBTU/Hr (John Zink PSMR)*	11.54 – 52.63	32.0**

Recommend In-stack NO2/NOx Ratios				
Refer #	**Fuel**	**Equipment Category (Controls)**	**Range of Ratios (%)**	**Recommended Ratio (%)**
IC Engines				
2	**Biogas**	200 BHP*	0.0 – 1.90	0.37**
1	**Diesel**	Default	20	20
		322 BHP (WP)*	0.0 – 50.0	15.64**
4	**NG**	Default – Lean Burn	5-10	10
2		120 BHP (3-Way Catalyst)*	0.1 – 2.83	0.9**
2		162 BHP (catalytic converter, air/fuel ratio)*	0.0 – 12.5	1.81**
2		165 BHP (3-Way Catalyst)*	0.0 – 17.58	3.16**
2		180 BHP (NSCR)*	1.02 – 3.41	1.82**
2		208 BHP (catalytic converter, air/fuel ratio)*	0.0 – 1.44	0.48**
2		1,070 BHP (LB/WP–Turbocharger/Intercooler)*	20.91 – 39.62	34.41**
2		1,529 BHP (LB - CO Catalyst, SCR)*	2.70 – 4.58	3.59**
2		2,775 BHP (SCR)*	14.53 – 26.33	19.46**
2		4,175 BHP (SCR,CO & VOC Catalysts)*	0.0 – 21.28	1.15**
Transportation Refrigeration Units (TRUs)				
5		CARB= CARB Diesel GTL = Gas To Liquid		

Fuel	Eng Speed	Exhaust	NO_2/ NO_x Ratio
CARB	High	Muffler	15.37
GTL	High	Muffler	16.17
CARB	High	pDPF	25.71
CARB	Low	Muffler	22.66
GTL	Low	Muffler	25.12
CARB	Low	pDPF	12.98

Truck / Cars				
6	**Gas/Diesel**	Light / Medium Duty	16-25	25
	Diesel	Heavy Duty	6-11	11
Turbines				
3	**NG**	GE Turbines	8.33 – 9.1	9.1
2a		Solar Centaur T-4702 (3.4 MW)***	8.43 – 12.42	10.32**

* Samples taken each minute or several minutes

**Value represents the statistical average of all data points

*** 30 min / 1 hour Source Test

L = Load ratings have been included in average

LB = Lean Burn

WP = Water Pump

Recommend In-stack NO2/NOx Ratios				
Refer #	Fuel	Equipment Category (Controls)	Range of Ratios (%)	Recommended Ratio (%)

References

1. Barrie Lawrence, Environmental Scientist, Government of Newfoundland and Labrador, “Guideline for Plume Dispersion Modeling” 1st Revision: November 20, 2006, Page 14
2. District Database “NO2 -NOx Ratio.mdb” - Data is based on CEMs, source test, and portable analyzer data collected in the San Joaquin Valley
   a. District Database “NO2 -NOx Ratio.mdb” - Data is based on source test data collected from out of state (Arkansas Department of Environmental Quality Office of Air Quality)
3. Roointon Pavri and Gerald D. Moore, GE Energy Services Atlanta, GA, “Gas Turbine Emissions and Control” March 2001 Page 63
4. Nigel N. Clark, Center for Alternative Fuels, Engines and Emissions Department of Mechanical and Aerospace Engineering West Virginia University Morgantown, WV 26506, “Selective NOx Recirculation for Stationary Lean-Burn Natural Gas Engines” April 30, 2007 Page 64
5. Robb A. Barnitt, National Renewable Energy Laboratory, “Emissions of Transport Refrigeration Units with CARB Diesel, Gas-to-Liquid Diesel, and Emissions Control Devices”, May 1, 2010
6. P G Boulter, I S McCrae, and J Green, Transportation research Laboratory, “Primary NIO2 Emissions From Road Vehicles in the Hatfield and Bell Commons Tunnels”, July 2007

Appendix J

Fumigation Modeling Results

SCREEN3 Fumigation Modeling

Nocturnal Fumigation - Inversion Break-up Fumigation

Max model scenario from crit pollutants modeling		Max Conc x/Q (ug/m^3/g/s)	Distance to max (m)	
NO2 1hr HRSG and coal dryer in startup 40% NG mode, TO startup, nitric acid plant on	HRSG max impact no fumigation simple terrain	0.9827	1,100	NO2 1hr HRSG Startup 40% NG mode Max Impact Scenario
	HRSG inversion Break-up Fumigation max impact	0.9865	18,896	
	Coal Dryer max impact no fumigation simple terrain	4.1410	900	NO2 1hr Coal Dryer Startup 40% NG mode Max Impact Scenario
	Coal Dryer Inversion Break-up Fumigation max impact	2.0100	10,783	
	TAIL TO max impact no fumigation simple terrain	6.5320	700	NO2 1hr Tail Gas Thermal Oxidizer Startup Max Impact Scenario
	TAIL TO Inversion Break-up Fumigation max impact	6.2710	4,785	
	Nitric Acid Plant max impact no fumigation simple terrain	6.2610	713	NO2 1hr Nitric Acid Plant
	Nitric Acid Plant max impact no fumigation simple terrain	6.3410	4,787	
SO2 1hr HRSG startup 80% natural gas mode, coal dryer normal emissions mix, TO startup	HRSG no fumigation simple terrain	0.9783	1,100	SO2 1hr HRSG Startup 80% NG mode Max Impact Scenario
	HRSG inversion Break-up Fumigation max impact	0.9620	19,252	
	Coal Dryer max impact no fumigation simple terrain	2.6240	1,000	SO2 1hr Coal Dryer Normal Ops mode
	Coal Dryer Break-up Fumigation max impact	1.5430	13,219	
	TAIL TO max impact no fumigation simple terrain	6.5320	700	SO2 1hr Tail Gas Thermal Oxidizer Startup Max Impact Scenario
	TAIL TO Inversion Break-up Fumigation max impact	6.2710	4,785	
CO 1hr HRSG shutdown 20% load NG mode, no coal dryer, TO normal process vent	HRSG max impact no fumigation simple terrain	0.9777	1,100	CO 1hr HRSG Shutdown 20% NG mode Max Impact Scenario
	HRSG inversion Break-up Fumigation max impact	0.9590	19,298	
	TAIL TO max impact no fumigation simple terrain	6.5320	700	CO 1hr Tail Gas Thermal Oxidizer normal process vent
	TAIL TO Inversion Break-up Fumigation max impact	6.2710	4,785	

Since the peak impacts occur at different locations the peak concentrations predicted from fumigation of all together sources will be greatly overpredicted.

	Emission Rate (g/s)	Xf = 1 hour fumigation conc (ug/m3)	X1 = 1 hour no fumigation conc (ug/m3)	Predicted conc for averaging time (ug/m3)	Background conc (ug/m3)	Total model + background conc (ug/m3)	
NO2 1 hr							
HRSG startup	13.5064	**13.324**	13.273	13.32			
COAL DRYER startup	1.9064	3.832	7.894	7.89			
TAIL_TO startup	2.8123	17.636	18.370	18.37			**NO OLM**
NITRIC ACID PLANT	0.5260	**3.336**	3.294	3.34			
				42.92	140	183	
SO2 1 hr							
HRSG Startup natural gas mode	0.5984	0.576	0.585	0.59			
COAL DRYER normal operations mode	0.1180	0.182	0.310	0.31			
TAIL_TO startup	0.2726	1.709	1.780	1.78			
				2.68	42	45	
CO 1 hr							
HRSG Shutdown 20% CTG load on NG no Coal Dryer	285.9802	274.255	279.603	279.60			
TAIL_TO normal process vent	0.3276	2.054	2.140	2.14			
				281.74	4581	4863	

for **2** cases the Xf is more than X1, therefore fumigation must be considered

Scenarios match worst case criteria pollutant modeling

Assumptions

Average annual temp: 63.4 F daily average Buttonwillow, WRCC AFC Table 5.1-2
Flat terrain only
No downwash
Add max impacts from all sources regardless of location, conservative
Distance to nearest fenceline:
HRSG: 454 m
Coal Dryer: 514 m
Thermal Oxidizer: 618 m
Nitric Acid Plant: 713 m
Closest receptor for each source are the distances above, plus receptors out to 10 km with receptor spacing every 100 m from fenceline receptor to 3 km, and every 500 m from 3 km to 10 km.

Appendix K

Commissioning Scenario Emissions and Modeling Results

HECA Emissions for all Commissioning Scenarios

	Maximum Hourly Emission Rates (lb/hr)				
Case 1	SO2	Nox	CO	VOC	PM10
One Diesel Generator	0.0	3.2	16.7	1.9	0.5
Power CT	0	0	0	0	1.1
Total	**0.03**	**3.2**	**16.7**	**1.9**	**1.6**
Case A	SO2	Nox	CO	VOC	PM10
Power Block CT	0	0	0	0	1.1
CTG @ 20% No Controls	2.1	67.1	2270	65	15
Total	**2.1**	**67.1**	**2270**	**65**	**16.1**
Case B	SO2	Nox	CO	VOC	PM10
Power Block CT	0	0	0	0	1.1
CTG @ 80% No Controls	4.8	391.2	344.5	3.8	15
Total	**4.8**	**391.2**	**344.5**	**3.8**	**16.1**
Case A2	SO2	Nox	CO	VOC	PM10
Power CT	0	0	0	0	1.1
ASU CT	0	0	0	0	0.2
Process CT	0	0	0	0	1.9
Flare Unshifted	4.1	140	4000	0	0
(NG) Coal Drying	0.3	4.5	44.2	1.9	0.9
(NG) HRSG 80%	4.7	34.1	26	5.9	15
Tail Gas Oxidizer	2.2	22.3	18.6	0.6	0.7
No CO2 Venting					
Total	**11.2**	**201.0**	**4088.8**	**8.4**	**19.8**
Case B2	SO2	Nox	CO	VOC	PM10
Power CT	0	0	0	0	1.1
ASU CT	0	0	0	0	0.2
Process CT	0	0	0	0	1.9
Flare Shifted	4.1	140.0	740.0	0.0	0.0
(NG) Coal Drying	0.3	4.53	44.22	1.9	0.9
(NG) HRSG 80%	4.7	34.1	26	5.9	15
Tail Gas Oxidizer	42.7	22.3	18.6	0.6	0.7
No CO2 Venting					
Total	**51.8**	**201.0**	**828.8**	**8.4**	**19.8**
Case C2	SO2	Nox	CO	VOC	PM10
Power CT	0	0	0	0	1.1
ASU CT	0	0	0	0	0.2
Process CT	0	0	0	0	1.9
H2 Rich Gas Flare	4.1	140.0	740.0	0.0	0.0
(NG) Coal Drying	0.3	4.53	44.22	1.9	0.9
(NG) HRSG 80%	4.7	34.1	26	5.9	15
Tail Gas Oxidizer (Normal Operation)	2.0	3.1	2.6	0.1	0.1
CO2 Vent	0	0	246	5.5	0
Total	**11.1**	**181.8**	**1058.8**	**13.4**	**19.2**
Case D2	SO2	Nox	CO	VOC	PM10
Power CT	0	0	0	0	1.1
ASU CT	0	0	0	0	0.2
Process CT	0	0	0	0	1.9
H2 Rich Gas Flare	3.6	123.8	654.2	0.0	0.0
PSA Off-Gas Flare	0.5	16.2	85.8	0.0	0.0
(NG) Coal Drying	0.3	4.53	44.22	1.9	0.9
(NG) HRSG 80%	4.7	34.1	26	5.9	15
Tail Gas Oxidizer (Normal Operation)	2.0	3.1	2.6	0.1	0.1
No CO2 Venting					
Total	**11.1**	**181.8**	**812.8**	**7.9**	**19.2**

Case E2	SO2	Nox	CO	VOC	PM10
Power CT	0	0	0	0	1.1
ASU CT	0	0	0	0	0.2
Process CT	0	0	0	0	1.9
H2 Rich Gas Flare	1.0	35.0	185.0	0.0	0.0
Coal Drying (H2)	0.9	17.6	21.4	0.6	1.4
HRSG (40% H2)	2.4	66.6	81	4.6	15
Tail Gas Oxidizer (Normal Operation)	2.0	3.1	2.6	0.1	0.1
CO2 Vent	0	0	246	5.5	0
Total	**6.3**	**122.3**	**536.0**	**10.8**	**19.7**

Case A3	SO2	Nox	CO	VOC	PM10
Power CT	0	0	0	0	1.1
ASU CT	0	0	0	0	0.2
Process CT	0	0	0	0	1.9
H2 Purified Flare	0.0	79.9	0.0	0.0	0.0
Coal Drying (Normal)	0.9	4.4	3.2	0.6	1.4
HRSG (normal)	4.1	25	18.3	3.5	15
Tail Gas Oxidizer (Normal Operation)	2.0	3.1	2.6	0.1	0.1
CO2 Vent (blend to CO2 purification)	0	0	103.4	0	0
Total	**7.0**	**112.4**	**127.5**	**4.2**	**19.7**

Case B3	SO2	Nox	CO	VOC	PM10
Power CT	0	0	0	0	1.1
ASU CT	0	0	0	0	0.2
Process CT	0	0	0	0	1.9
H2 Rich Gas Flare	0.0	79.9	0.0	0.0	0.0
Coal Drying (Normal)	0.9	4.4	3.2	0.6	1.4
HRSG (normal)	4.1	25	18.3	3.5	15
Tail Gas Oxidizer (Normal Operation)	2.0	3.1	2.6	0.1	0.1
CO2 Vent (high purity)	0	0	103.4	0	0
Ammon S/U Heater	0.1	0.5	1.5	0.2	0.2
Total	**7.1**	**112.9**	**129.0**	**4.3**	**19.9**

Case C3	SO2	Nox	CO	VOC	PM10
Power CT	0	0	0	0	1.1
ASU CT	0	0	0	0	0.2
Process CT	0	0	0	0	1.9
Coal Drying	0.9	4.4	3.2	0.6	1.4
HRSG (normal)	4.1	25	18.3	3.5	15
Tail Gas Oxidizer (Normal Operation)	2.0	3.1	2.6	0.1	0.1
Nitric Acid Nox Abator	0.0	60.0	0.0	0.0	0.2
Total	**7.0**	**92.5**	**24.1**	**4.2**	**19.9**

Flare Stack Parameters for Commissioning Modeling Scenarios

Parameter	Gasification Flare (unshifted) Case A2	Gasification Flare (shifted) Case B2	Gasification Flare (H2 Rich) Case C2	Gasification Flare (H2 Rich gas, PSA Off-Gas Flare) Case D2	Gasification Flare (H2 Rich Gas) Case E2	Gasification Flare (H2 Purified) Case A3 and B3
Heat release rate for flare+pilot, (10^6 Btu/hr HHV)	2000	2000	2,000	2,000	500	1142
H = Total Heat release rate (cal/s)	1.40E+08	1.40E+08	1.40E+08	1.40E+08	3.50E+07	7.99E+07
Fb = Buoyancy flux	2.32E+03	2.32E+03	2.32E+03	2.32E+03	5.81E+02	1.33E+03
Q_H = sensible heat release rate	6.30E+07	6.30E+07	6.30E+07	6.30E+07	1.57E+07	3.60E+07
Actual Stack height (m)	76.2	76.2	76.2	76.2	76.2	76.2
GEP stack height for modeling (m)	65	65	65	65	65	65
AERMOD Input parameters						
He = Effective stack height (m) as calculated in SCREEN3	100.71	100.71	100.71	100.71	83.41	92.32
T = Stack temperature (K)	1273	1273	1273	1273	1273	1273
v = Exit velocity (m/s)	20	20	20	20	20	20
d = effective stack diameter (m)	7.842	7.842	7.842	7.842	3.921	5.926

Flare stack parameters are based on calculated using the SCREEN3 technique
Fb = Buoyancy flux = 1.66 x 10-5 x H
QH = sensible heat release rate = 0.45 x H
He = Effective stack height (m) = Hs + 4.56E-03 * H^0.478
BTU/hr to cal/sec 0.06999882

HECA Modeling Results for all Commissioning Scenarios

Modeling Scenario	Pollutant	Averaging Period	Maximum Estimated Impact (mg/m^3)	Background[1] (mg/m^3)	Monitoring Station Description[1]	Total Predicted Concentration (mg/m^3)	Most Stringent Standard (mg/m^3)[2]
Case 1	CO	1-hour	144.64	4,581	a	4725.64	23,000
		8-hour	46.38	2,485	a	2531.38	10,000
	SO_2	1-hour	0.26	42	d	42.26	655
		24-hour	0.03	13	d	13.03	105
	NO_2[3]	1-hour	24.94	140	b	164.94	339
	PM_{10}	24-hour	0.95	264	c	264.55	50
Case A	CO	1-hour	1975.17	4,581	a	6556.17	23,000
		8-hour	801.25	2,485	a	3286.25	10,000
Case B	SO_2	1-hour	4.18	42	d	46.18	655
		24-hour	0.85	13	d	13.85	105
	NO_2[3]	1-hour	149.73	140	b	289.73	339
Case A2	CO	1-hour	565.85	4,581	a	5146.85	23,000
		8-hour	147.91	2,485	a	2632.91	10,000
	SO_2	1-hour	4.18	42	d	46.18	655
		24-hour	0.85	13	d	13.85	105
	NO_2[3]	1-hour	38.36	140	b	178.36	339
	PM_{10}	24-hour	3.40	264	c	267.00	50
Case B2	SO_2	1-hour	97.43	42	d	139.43	655
		3-hour	37.51	26	d	63.51	1,300
		24-hour	7.48	13	d	20.48	105
	NO_2[3]	1-hour	38.36	140	b	178.36	339
Case C2	CO	1-hour	1097.41	4,581	a	5678.41	23,000
		8-hour	178.21	2,485	a	2663.21	10,000
Case D2	NO_2[3]	1-hour	23.43	140	b	163.43	339
Case E2	CO	1-hour	914.50	4,581	a	5495.50	23,000
		8-hour	146.67	2,485	a	2631.67	10,000
	NO_2[3]	1-hour	66.76	140	b	206.76	339
Case B3	CO	1-hour	384.78	4,581	a	4965.78	23,000
		8-hour	61.38	2,485	a	2546.38	10,000
	SO_2	1-hour	5.53	42	d	47.53	655
		24-hour	0.92	13	d	13.92	105
	NO_2[3]	1-hour	23.23	140	b	163.23	339
Case C3	NO_2[3]	1-hour	128.32	140	b	268.32	339
	PM_{10}	24-hour	3.51	264	c	267.11	50

Source: HECA Project 2012

Notes:

1. Background Concentrations are maximum concentrations from the last 3 years of available EPA AirData and/or CARB data at the following stations
   - a) Bakersfield Golden State Highway Monitoring Station, Maximum Concentration 2007-2009
   - b) Shafter Monitoring Station, Maximum Concentration 2009-2011
   - c) Bakersfield California Avenue Monitoring Station, Maximum Concentration 2008-2010
   - d) Fresno 1st Street Monitoring Station Maximum Concentrations, 2007-2009 for 3-hour SO_2, 2009-2011 for 1-hour and 24 -hour SO2
2. Although there is a NAAQS for SO2 and NO2 1-hour impacts from commissioning activities are only be compared to the CAAQS due to the infrequent nature of the commissioning activities.
3. NO_2 modeling for commissioning was conducted with the PVMRM algorithm.

CO = carbon monoxide

NO_2 = nitrogen dioxide

PM_{10} = particulate matter less than 10 microns in diameter

SO_2 = sulfur dioxide

$\mu g/m^3$ = micrograms per cubic meter