URS

DOCKET
08-AFC-8
DATE JUN 21 2010
RECD. JUN 22 2010

June 21, 2010

Dockets Unit
California Energy Commission
1516 Ninth Street, MS 4
Sacramento, CA 95814

RE: Hydrogen Energy California Project
Application for Certification 08-AFC-8

On behalf of HECA LLC, the applicant for the above-referenced Hydrogen Energy California AFC, we are pleased to submit one print copy and one CD of the enclosed document:

- *Response to the April 12, 2010 CEC Data Response and Issues Resolution Workshop, Request No. 40*

Additionally we are providing the enclosed DVD containing air quality modeling files to the CEC.

In accordance with the CEC's Filing and Electronic Document Directives for this project, the enclosed document is being provided to individuals on the Proof of Service list on CD because the size of the electronic document may prevent reliable email service and the printed document exceeds 50 pages. A paper copy of the document can be provided upon request to me at 415-243-3708 or dale_shileikis@urscorp.com.

The enclosed document is being submitted to the CEC for docketing.

URS Corporation

Dale Shileikis
Vice President, Environmental Services

Enclosures
CC: Rod Jones (w/o enclosure)

URS Corporation
Post Montgomery Center
One Montgomery Street, Suite 900
San Francisco, Ca 94104-4538
Tel: 415.896.5858
Fax: 415.882.9261
www.urscorp.com

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE *HYDROGEN ENERGY CALIFORNIA PROJECT*

Docket No. 08-AFC-8

PROOF OF SERVICE LIST
(Rev. 5/10/10)

APPLICANT

Gregory D. Skannal
Tiffany Rau
Rick Harrison
Hydrogen Energy International LLC
One World Trade Center, Suite 1600
Long Beach, CA 90831
gregory.skannal@hydrogenenergy.com
tiffany.rau@hydrogenenergy.com
rick.harrison@hydrogenenergy.com

Asteghik Khajetoorians,
Senior BP Legal Attorney
BP America, Inc.
6 Centerpointe Drive, LPR 6-550
La Palma, CA 90623
Asteghik.Khajetoorians@bp.com

APPLICANT'S CONSULTANT

Dale Shileikis, Vice President
Energy Services Manager
Major Environmental Programs
URS Corporation
221 Main Street, Suite 600
San Francisco, CA 94105-1917
dale_shileikis@urscorp.com

COUNSEL FOR APPLICANT

Michael J. Carroll
Latham & Watkins, LLP
650 Town Center Drive, 20th Fl.
Costa Mesa, CA 92626-1925
michael.carroll@lw.com

INTERESTED AGENCIES

California ISO
e-recipient@caiso.com

INTERVENORS

Tom Frantz
Association of Irritated Residents
30100 Orange Street
Shafter, CA 93263
tfrantz@bak.rr.com

Kern-Kaweah Chapter
of the Sierra Club
Babak Naficy
Law Offices of Babak Naficy
1504 Marsh Street
San Luis Obispo, California
93401
babaknaficy@sbcglobal.net

***Environmental Defense Fund (EDF)**
Timothy O'Connor, Esq.
1107 Ninth St., Suite 540
Sacramento, CA 95814
toconnor@edf.org

ENERGY COMMISSION

JAMES D. BOYD
Vice Chair and Presiding Member
jboyd@energy.state.ca.us

JEFFREY D. BYRON
Commissioner and Associate Member
jbyron@energy.state.ca.us

Raoul Renaud
Hearing Officer
rrenaud@energy.state.ca.us

Kristy Chew
Adviser to Commissioner Boyd
kchew@energy.state.ca.us

Rod Jones
Project Manager
rjones@energy.state.ca.us

Lisa De Carlo
Staff Counsel
ldecarlo@energy.state.ca.us

Jennifer Jennings
Public Adviser's Office
publicadviser@energy.state.ca.us

DECLARATION OF SERVICE

I, Dale Shileikis , declare that on June 18, 2010, I served and filed copies of the attached *Response to the April 12, 2010 CEC Data Response and Issues Resolution Workshop, Request No. 40*, dated June, 2010. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[www.energy.ca.gov/sitingcases/hydrogen_energy]**.

The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

FOR SERVICE TO ALL OTHER PARTIES:

_______ sent electronically to all email addresses on the Proof of Service list

X by personal delivery or by depositing in the United States mail at San Francisco, CA with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses **NOT** marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

X sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (***preferred method***);

OR

_______ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 08-AFC-8
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

Dale Shileikis
____

Response to
the April 12, 2010 CEC Data Response and Issues Resolution Workshop Request No. 40

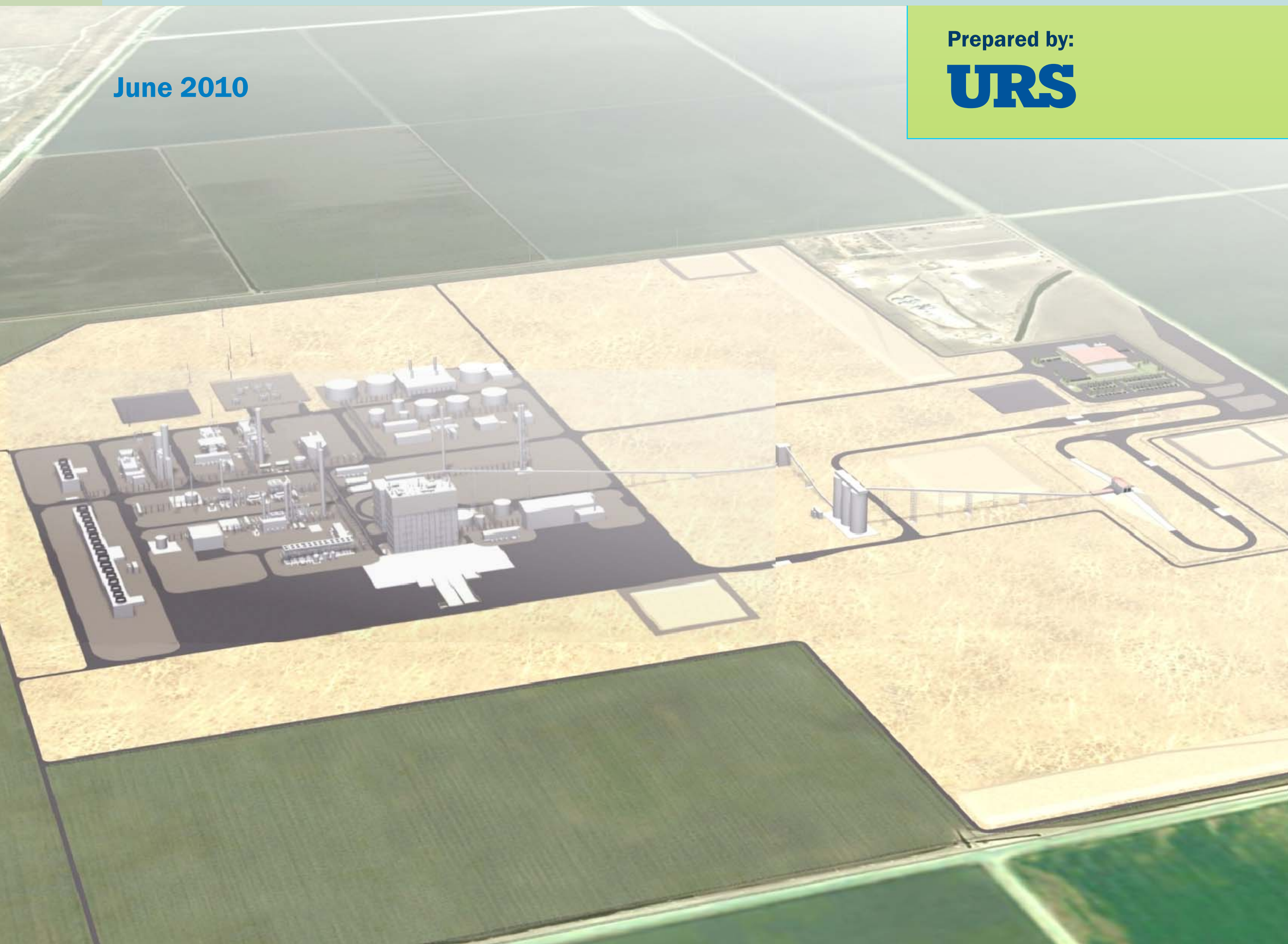
Revised
Application for Certification (08-AFC-8)
for
HYDROGEN ENERGY CALIFORNIA
Kern County, California

Prepared for:
Hydrogen Energy International LLC

Submitted to:
California Energy Commission

Prepared by:
URS

June 2010



Technical Areas: Air Quality and Public Health
Technical Leads: William Walters and Dr. Alvin Greenberg

WORKSHOP REQUEST

40. Subsequent to the Workshop, CEC staff requested a summary of the refinements that have occurred to the modeling for air quality and public health since the submittal of the AFC Amendment, details on how the emissions from each source changed, and a DVD of the modeling files.

RESPONSE

The information is provided in Attachment 40-1 and on the accompanying DVD.

ATTACHMENT 40-1

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TABLES

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APPENDICES

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ACRONYMS

AAQS	Ambient Air Quality Standards
AFC	Application for Certification
AQRV	Air Quality Related Values
BACT	best available control technology
CAAQS	California Ambient Air Quality Standards
C_3H_6	propylene
CEC	California Energy Commission
CH_3OH	methanol
CO	carbon monoxide
CO_2	carbon dioxide
COS	carbonyl sulfide
CT	combustion turbine
CTG	combustion turbine generator
DPM	diesel particulate matter
ºF	degrees Fahrenheit
GE	General Electric
GHG	greenhouse gas
g/s	grams per second
H_2S	hydrogen sulfide
HCN	hydrogen cyanide
HECA	Hydrogen Energy California
HHV	higher heating value
hr	hours
HRA	Health Risk Assessment
HRSG	heat recovery system generator
K	Kelvin
lbs/MWh	pounds per megawatt hour
LDAR	leak detection and repair
LHV	lower heating value
MDEA	methyl diethanolamine
MEIR	maximally exposed individual resident
MEIW	maximally exposed individual worker
$\mu g/m^3$	micrograms per cubic meter
MMBtu/hr	million British thermal units per hour
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NAD	North American datum
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia
NO_2	nitrogen dioxide
NO_X	nitrogen oxide
O&M	operation and maintenance
OLM	ozone-limiting method
PDOC	preliminary determination of compliance
PM_{10}	particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
ppb	parts per billion
ppm	parts per million
ppmv	parts per million by volume
ppmvd	parts per million volumetric dry
PSD	Prevention of Significant Deterioration

PVMRM	plume volume molar ratio method
Revised AFC	Revised Application for Certification
SCR	selective catalytic reaction
SILs	Significant Impact Levels
SJVAPCD	San Joaquin Valley Air Pollution Control District
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SO_2	sulfur dioxide
SO_X	sulfur oxides
SRU	sulfur recovery unit
TAC	toxic air contaminant
TGTO	Tail Gas Thermal Oxidizer
USEPA	U.S. Environmental Protection Agency
VOC	volatile organic compound

During the process of developing the San Joaquin Valley Air Pollution Control District (SJVAPCD) air permit, Hydrogen Energy California (HECA) engineers revised a few of the Project operating conditions described in the Revised Application for Certification (AFC) and subsequent Amendment to the Revised AFC. This document outlines how these Project refinements affect the air quality emissions and subsequent air quality impact analysis. These refinements are reflected in the air permit preliminary determination of compliance (PDOC) created by the SJVAPCD.

The refinements primarily reflect the need for more startups and shutdowns to account for offline turbine washing that are recommended by General Electric (GE) for maintenance, along with ancillary activities during those washes.

This document provides a detailed discussion of the refinements. Tables and figures that have been changed as a result of these refinements are included in this document.

These refinements modify emissions rates, but do not fundamentally alter the nature of the Project, nor do they affect the proposed capture and sequestration of Project carbon emissions. This attachment describes the Project refinements and analyzes whether or not they result in any new significant impacts. The emissions of criteria pollutants, toxic air contaminants, and greenhouse gases (GHG) increase as a result of Project refinements. However, the AERMOD and HARP modeling results demonstrate that the Project refinements are expected to remain less than significant.

The Project refinements primarily consist of modifications associated with the need for more startups and shutdowns to account for the offline turbine washing that is recommended by GE for maintenance.

The refinements would not result in changes to the amount of power produced, the plot plan, schedule, workforce, traffic, or construction equipment use.

The Project refinements examined in this document are outlined below for each affected source.

2.1 COMBUSTION TURBINE GENERATOR/HEAT RECOVERY SYSTEM GENERATOR

To account for the combustion turbine generator (CTG) washes and other possible maintenance, 10 hot startups were added. Thus, the number of startups and shutdowns was refined to:

- Cold startups = 10 per year
- Hot startups = 20 per year
- Shutdowns = 30 per year
- Normal Operations with Duct Burning = 8,257 hours per year
- Total Hours of operations = 8,322 hours per year (95 percent)

In the Revised AFC and subsequent Amendment to the Revised AFC, a duct burner heating value of 500 million British thermal units (MMBtu) per hour (hr) was incorrectly used as the higher heating value [HHV] in the emission calculations. However, that value is actually the lower heating value (LHV). The calculations have been revised to use the correct duct burner heating value of 550 MMBtu/hr HHV. This resulted in the CTG/heat recovery system generator (HRSG) hourly emissions to increase slightly for sulfur dioxide (SO_2) when firing natural gas, and all pollutants except for particulate matter less than 10 microns in diameter (PM_{10})/particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) when cofiring natural gas and syngas.

The worst-case daily emissions were estimated based on a maximum of one cold startup, one hot startup, and one shutdown, with the remainder of the time at maximum normal operating emissions. To account for the increase in CTG startups and shutdowns, the annual emissions increase slightly for all pollutants except ammonia and particulate matter.

2.2 GASIFICATION FLARE

During the turbine washes, hydrogen-rich fuel will be diverted to the gasification flare. A turbine wash is expected to take 12 hours, during which time the gasifier will operate at a reduced capacity (70 percent). Four turbine washes are planned annually, which add up to approximately 81,400 MMBtu per year (yr) of flaring. The total planned usage of the gasifier flare is expected to be 196,600 MMBtu/yr of flaring; this includes turbine washes and gasifier startups and shutdowns.

Each CTG wash is expected to take 12 hours, although 24 hours was assumed to estimate worst-case daily emissions. It is expected that up to 1,695 MMBtu/hr of syngas could be flared during a turbine wash.

2.3 SULFUR RECOVERY UNIT FLARE

To more accurately account for the time expected to startup the gasifier, the sulfur recovery unit (SRU) may flare for up to 40 hours per year. This is an increase from the 6 hours per year previously proposed in the Revised AFC. Maximum daily flaring is based on a gasifier startup of 12 hours.

2.4 GASIFIER REFRACTORY HEATERS

Based on operations from similar facilities, it was determined that each refractory heater should be permitted to operate up to 1,200 hours per year; this is an increase in operations previously proposed in the Revised AFC. For estimating worst-case hourly and daily emissions, two heaters may operate at full load for the entire period. When gasifiers are switched, for gasifier maintenance purposes, two may operate at the same time. The vendor provided emission factors for nitrogen dioxide (NO_2) and carbon dioxide (CO) are higher than the U.S. Environmental Protection Agency (U.S. EPA) AP-42 emission factors previously used to estimate these emissions.

2.5 AUXILIARY BOILER

SJVAPCD determined that selective catalytic reduction (SCR) was the best available control technology (BACT) for the auxiliary boiler. This reduces the nitrogen oxide (NO_x) emissions from the boiler. The boiler will now also have some ammonia slip.

2.6 TAIL GAS THERMAL OXIDIZER

No modifications were made to the operation of the Tail Gas Thermal Oxidizer (TGTO), although the emission calculations were updated to ensure the examination of incineration from one stream at a time. Annual emissions are slightly lower due to new calculations.

2.7 DIESEL EMERGENCY GENERATORS

The maintenance operation schedule was changed to 52 hours per year for each engine. Emission factors for U.S. EPA Offroad Tier 4 engines were used as discussed in the response to California Energy Commission (CEC) Set One Data Request No. 30.

2.8 DIESEL EMERGENCY FIRE WATER PUMP

Emission factors for U.S. EPA Offroad Tier 4 engines were used as discussed in the response to CEC Set One Data Request No. 30.

2.9 CARBON DIOXIDE VENT

Upon further examination it was determined that the concentration of carbonyl sulfide (COS) in the carbon dioxide (CO_2) stream should not exceed 43 parts per million by volume (ppmv); this reduces the COS emissions from the emergency CO_2 venting.

2.10 FUGITIVE EMISSIONS

In response to CEC Set One Data Request Nos. 17 and 89, emissions from fugitive leaks in the piping and components were included in the total facility inventory. These emissions were included in the criteria pollutant and toxic air contaminants (TAC) modeling analyses presented in this document.

2.11 OPERATIONS AND MAINTENANCE VEHICLES

In response to CEC Set One Data Request Nos. 23 and 24, emissions from 10 light heavy-duty gasoline trucks and 10 light heavy-duty diesel trucks used for onsite maintenance were included in the modeling analyses.

2.12 RECTISOL FLARE, COOLING TOWERS, MATERIAL HANDLING, AND FEEDSTOCK DELIVERY

No revisions were made to the operation or emissions from the rectisol flare, cooling towers, or the handling of materials.

This section discusses emission changes associated with potential environmental impacts associated with the Project refinements. The emission sections discuss the changes associated with the Project refinements. All other emission calculation techniques remained the same as presented in the Revised AFC, Amendment to the Revised AFC, and responses to CEC Data Requests. Operational criteria pollutant emission calculations for all sources are presented in Appendix A of this document. The Project refinements do not affect the either the construction or commissioning emissions; thus, these emissions are not discussed in this document, although modeling was conducted to show compliance with the new federal 1-hour NO_2 standard.

3.1 AIR QUALITY

3.1.1 Construction Emissions

No changes to the construction activities are expected from the Project refinements. Therefore, the construction emissions calculated and modeled in the Applicant's response to CEC Set One Data Request No. 6 accurately characterize the potential air quality impacts during construction with the Project refinements incorporated. The Project refinements would not change the conclusions in Section 5.1 of the Revised AFC or the response to CEC Set One Data Request No. 6, and potential air quality impacts during construction are expected to remain less than significant.

Construction modeling was conducted to show compliance with the new federal 1-hour NO_2 standard. The modeling techniques used in the analysis are discussed in Section 3.1.3 and the results are discussed in Section 3.1.4.

3.1.2 Operational Emissions

Operational Emissions – Stationary Sources

An overview of the Project refinements as they affect each source is provided above in Section 2. This section describes details regarding emission changes to affected sources. The updated emission rates are presented in Table 1, Total Combined Annual Criteria Pollutant Emissions.

CTG/HRSG Operating Emissions

As presented in the Revised AFC and Amendment to the Revised AFC, the maximum short-term operational emissions from the CTG/HRSG were determined from a comparative evaluation of potential emissions corresponding to normal operating conditions (including HRSG duct-firing), and CTG startup/shutdown conditions. The long-term operational emissions from the CTG/HRSG were estimated by summing the emissions contributions from normal operating conditions (including hours with duct-firing) and CTG/HRSG startup/shutdown conditions. Estimated annual emissions of air pollutants for the CTG/HRSG have been calculated based on the expected operating schedule for the CTG/HRSG presented in Table 2, Maximum CTG/HRSG Operating Schedule. Although the number of startups and shutdowns was revised, the technique for calculating the emissions associated with these activities did not change.

The change of the duct burner heating value to 550 MMBtu/hr HHV caused the CTG/HRSG emissions to increase slightly for SO_2 when firing natural gas, and all pollutants but PM_{10} when cofiring natural gas and syngas. These revised duct burner emissions were calculated by Project engineers and then added to the CTG emissions, which did not change.

Table 1
Total Combined Annual Criteria Pollutant Emissions

Pollutant	Total Annual	CTG/HRSG Stack Maximum[1]	Cooling Towers[2]	Auxiliary Boiler	Emergency Generators[3]	Fire Water Pump[4]	Gasification Flare	SRU Flare	Rectisol Flare	Tail Gas Thermal Oxidizer	CO_2 Vent	Gasifier Refractory Heaters	Feed-stock[5]	Fugitives[5]
NO_X	195.1	168.0	--	0.9	0.2	0.1	7.2	0.2	0.2	10.5	--	7.8	--	--
CO	406.9	155.7	--	5.8	0.9	0.2	111.2	0.2	0.1	8.8	106.9	11.3	--	6.0
VOC	59.1	33.8	--	0.6	0.10	0.01	0.003	0.003	0.002	0.3	2.4	2.3	--	19.7
SO_2	37.7	28.3	--	0.3	0.001	0.0003	0.118	0.372	0.003	8.5	--	0.07	--	--
PM_{10}	111.4	82.3	24.1	0.8	0.02	0.001	0.007	0.006	0.004	0.4	--	0.3	3.6	--
$PM_{2.5}$[6]	99.2	82.3	14.5	0.8	0.02	0.001	0.007	0.006	0.004	0.4	--	0.3	1.0	--
NH_3	76.3	75.8	--	0.3	--	--	--	--	--	--	--	--	--	0.2
H_2S	3.7	--	--	--	--	--	--	--	--	--	1.3	--	--	2.4

Source: HECA Project

Notes:

[1] Total annual HRSG emissions represent the maximum emissions rate from firing hydrogen-rich fuel, natural gas, or co-firing.
[2] Includes contributions from all three cooling towers.
[3] Includes contributions from both emergency generators.
[4] VOC emissions for fire pump engine are combined with NO_X.
[5] Feedstock emissions are shown as the contribution of all dust collection points.
[6] Where PM_{10} = $PM_{2.5}$ it is assumed all PM_{10} is $PM_{2.5}$.

CO = carbon monoxide
H_2S = hydrogen sulfide
HRSG = heat recovery system generator
NH_3 = ammonia
NO_X = nitrogen oxide
$PM_{2.5}$ = particles less than 2.5 micrometers in diameter
PM_{10} = particles less than 10 micrometers in diameter
SO_2 = sulfur dioxide
VOC = volatile organic compound

Table 2
Maximum CTG/HRSG Operating Schedule

Operating Conditions	Annual Numbers
Total Hours of Operation	8,322
Total Number of Cold Starts	10
Cold Start Duration (hour)	3
Total Number of Hot Starts	20
Hot Start Duration (hour)	1
Total Number of Shutdowns	30
Shutdown Duration (hour)	0.5
Duct Burner Operation (hour)	8,257

Source: HECA Project

Notes:

CTG = combustion turbine generator
HRSG = heat-recovery steam generator

CTG/HRSG Emissions Scenarios for Modeling

Reasonable worst-case short-term emissions from the turbines were calculated for use in the air quality modeling. These scenarios form the basis for the air dispersion modeling analyses presented in Section 3.1.3, Dispersion Modeling.

Worst-case 8-hour and 24-hour emissions were based on a maximum of one cold startup, one hot startup, and one shutdown, with the remainder of the time at maximum normal operating emissions.

Table 3, Criteria Pollutant Sources and Emission Totals for the Worst-Case CTG Emissions Scenario for All Averaging Times, summarizes the worst-case emissions scenarios adopted to assess maximum impacts to air quality and air quality–related values in the modeling analyses presented in Section 3.1.3.

Estimated annual emission totals for all pollutants incorporate the maximum anticipated emissions related to startups and shutdowns, as well as the maximum steady-state operating emissions with duct firing. Estimated maximum annual emissions for the GE 7FB turbine are presented in Table 4, Average Annual Emissions per Turbine Operating Scenario. Emissions calculations for all scenarios, including revisions, are contained in Appendix A.

Auxiliary Boiler Emissions

SJVAPCD determined that SCR was BACT for the auxiliary boiler; therefore, the NO_x emissions from the boiler were reduced. NO_X emissions are based on 5 parts per million volumetric dry (ppmvd) at 3 percent O_2, with installation of SCR.

A summary of the annual auxiliary boiler emissions is presented in Table 1. Emissions and calculations are included in Appendix A.

Gasification Flare

During the turbine washes, hydrogen-rich fuel will be diverted to the gasification flare. A turbine wash is expected to take 12 hours, during which time the gasifier will operate at a reduced capacity (70 percent).

Table 3
Criteria Pollutant Sources and Emission Totals for the Worst-Case CTG Emissions Scenario for All Averaging Times

Averaging Time	Worst-Case Emission Scenarios by Operating Equipment	Pollutant	Emissions in Pounds – Entire Period	
			CTG/HRSG	Fuel
1 hour	**NO_X:** Hot startup hour	NO_X	167.0	All fuels
	CO: Cold startup hour	CO	1,679.7	All fuels
	SO_X: Full-load turbine operation with duct firing at peak fuel use	SO_X	6.8	Hydrogen-Rich Fuel
3 hour	**SO_X:** Full-load turbine operation with duct firing at peak fuel use	SO_X	20.5	Hydrogen-Rich Fuel
8 hour	**CO:** One cold start, one hot start, one shutdown and remainder of period at full load operation with duct firing at peak fuel use	CO	5,671.0	Co-firing
24 hour	**NO_X:** One cold start, one hot start, one shutdown and remainder of period at full load operation with duct firing at peak fuel use	NO_X	1,275.9	Hydrogen-Rich Fuel
	SO_X, PM_{10}/$PM_{2.5}$: Continuous full-load turbine operation with duct firing at peak fuel use	$PM_{10} = PM_{2.5}$	475.2	Natural Gas or Co-firing
		SO_X	163.8	Hydrogen-Rich Fuel
Annual	**NO_X, CO, PM_{10}/$PM_{2.5}$ and SO_X:** 10 cold starts, 20 hot starts, 30 shutdowns and 8,257 hours of turbine operates at full load with duct firing	NO_X	336,053	Hydrogen-Rich Fuel
		CO	311,417	Co-firing
		$PM_{10} = PM_{2.5}$	164,607	Natural Gas or Co-firing
		SO_X	56,690	Hydrogen-Rich Fuel

Source: HECA Project

Notes:

CO = carbon monoxide
CTG = combustion turbine generator
^oF = degrees Fahrenheit
HRSG = heat recovery steam generator
NO_X = nitrogen oxides
PM_{10}: = particulate matter less than 10 microns in diameter, and is assumed to equal $PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
SO_X = sulfur oxides
VOC = volatile organic compounds

Table 4
Average Annual Emissions per Turbine Operating Scenario

Pollutant	HRSG Stack – Natural Gas (tons/yr/CT)	HRSG Stack – (Hydrogen-Rich Fuel) (tons/yr/CT)	HRSG Stack – Co-Firing (tons/yr/CT)	Maximum (tons/yr/CT)
NO_X	148.0	168.0	167.8	168.0
CO	141.2	105.9	155.7	155.7
VOC	30.5	19.6	33.8	33.8
SO_2	20.5	28.3	24.7	28.3
$PM_{10} = PM_{2.5}$	74.9	82.3	82.3	82.3
NH_3	66.9	75.8	75.7	75.8

Source: HECA Project

Notes:

CO = carbon monoxide
CT = combustion turbine
HRSG = heat recovery steam generator
NH_3 = ammonia
NO_X = nitrogen oxides
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
PM_{10} = particulate matter less than 10 microns in diameter
SO_2 = sulfur dioxide
VOC = volatile organic compounds

During a turbine wash, the maximum hourly flaring rate of shifted hydrogen-rich fuel will be 1,695 MMBtu/hr. To estimate the worst-case daily emissions, 24 hours of flaring at this rate was assumed, although it should be noted that this is not expected to occur. Maximum daily $PM_{10}/PM_{2.5}$ emissions from the gasification flare are based on 24 hours of pilot operation, since during a turbine wash hydrogen-rich fuel, which contains negligible amounts of PM, will be flared. Four turbine washes are planned annually.

The total planned gasifier flare usage is outlined in Table 5. This flaring includes turbine washes and gasifier startups and shutdowns. Annual emissions were based on the flaring outlined in Table 5.

Table 5
Planned Annual Gasifier Flare Usage

Event	Maximum Gas Flared (MMBtu/yr)	Event/yr	Percentage Unshifted	Unshifted Gas (MMBtu/yr)	Shifted Gas (MMBtu/yr)
Cold plant startup:	30,000	1	20%	6,000	24,000
Plant shutdown:	500	1	100%	500	0
Gasifier outages:	60,000	24	100%	60,000	0
Gasifier hot restarts:	25,000	12	100%	25,000	0
Off-line CTG wash:	81,400	12	0%	0	81,400
Totals (MMBtu/yr):	**196,900**			**91,500**	**105,400**

Notes:

CTG = combustion turbine generator
MMBtu/yr = million British thermal units per year

SRU Flare

To more accurately account for the time expected to be needed for gasifier startup, the SRU may flare for up to 40 hours per year. Estimates of daily flare emissions were based on a maximum of 12 hours of flare operation, although this is expected to be an overestimate. Emissions for the SRU flare were calculated using the same emission factors and techniques outline in the Revised AFC.

Gasifier Refractory Heaters

The gasifier refractory heaters operate at 18 million MMBtu/hr, firing natural gas for 1,200 hours per year each, for a total of 3,600 hours per year. Emission factors for NO_2 and CO were revised to reflect vendor guaranteed rates. Table 6 outlines these emission factors and the associated emissions. Worst-case hourly and daily emissions were estimated assuming two heaters may operate simultaneously at full load for the entire period.

Table 6
Emissions Factors for NO_2 and CO and Associated Emissions

Pollutant	Gasifier Pollutant Emission Factors (lb/MMBtu, HHV)	Maximum Hourly Emissions Total Heaters (lb/hr)	Maximum Daily Emissions Total Heaters (lb/day)	Maximum Annual Emissions Total Heaters (ton/yr)
NO_x	0.24	8.64	207.36	7.78
CO	0.35	12.60	302.40	11.34
VOC	0.07	2.52	60.48	2.27
SO_2	0.00	0.07	1.76	0.07
$PM_{10} = PM_{2.5}$	0.01	0.29	6.91	0.26

Notes:
CO = carbon monoxide
HHV = higher heating value
lb = pounds
MMBtu = million British thermal units
NO_X = nitrogen oxides
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
PM_{10} = particulate matter less than 10 microns in diameter
SO_2 = sulfur dioxide
VOC = volatile organic compound

Tail Gas Thermal Oxidizer

No revisions were made to the operation of the TGTO., It is expected to incinerate SRU startup waste gas for up to 300 hours per year, and the remainder of the year (8,460 hours) it will incinerate process vent gas. During incineration of either gas there will be 10 MMBtu/hr of natural gas assist gas. In the Revised AFC the assist gas emissions were counted twice for the 300 hours of SRU startup waste gas disposal. Emission factors are based on previous project engineering data and U.S. EPA AP-42 for natural gas external combustion.

Diesel Emergency Generators

The maintenance operation schedule was changed to 52 hours per year for each engine. Emission factors for U.S. EPA Offroad Tier 4 engines were used as discussed in the response to CEC Set One Data Request No. 30.

Diesel Emergency Fire Water Pump

Emission factors for U.S. EPA Offroad Tier 4 engines were used as discussed in the response to CEC Set One Data Request No. 30.The maintenance schedule for testing the fire water pump remains 100 hours per year.

CO_2 Vent

Criteria pollutant emissions from the CO_2 vent are unchanged from those presented in the Revised AFC.

Fugitive Emissions

In response to CEC Set One Data Request Nos. 17 and 89, emissions from fugitive leaks in the piping and components were included in the total facility inventory.

Potential fugitive VOC emissions from piping components were estimated using the U.S. EPA guidance, *Protocol for Equipment Leak Emission Estimates* (1995). The emission factors used in the calculations are for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) factors and are presented in Table 7. A leak detection and repair (LDAR) program will be implemented on select process areas with the largest TAC and VOC fugitive emissions. The LDAR program implemented will meet the National Emission Standard for Hazardous Air Pollutants (NESHAPS) regulations.

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. The control efficiencies for such a program are presented in Table 7.

Table 7
Fugitive Emission Factors, Control Efficiencies for LDAR Program and Component Count

Component Type	Service Type	TOC Emission Factor (kg/hr/source)	Control Efficiency	Total Componen t Count
Valves	Gas	5.97E-03	92%	1,156
	Light Liquid	4.30E-03	88%	1,141
	Heavy Liquid	2.30E-04	0%	840
Pump Seals	Light Liquid	1.99E-02	75%	17
	Heavy Liquid	8.62E-03	0%	26
Compressor Seals	Gas	2.28E-01	0%	3
Connectors	All	1.83E-03	93%	9,293

Notes:

Emission factors and control efficiencies are from EPA's 1995 "Protocol for Equipment Leak Emission Estimates" from Table 2-1 (SOCMI Average Emission Factors) and Table 5-2 (Control Effectiveness for an LDAR Program at a SOCMI Process Unit).

kg/hr/source = kilogram per hour per source
SOCMI = Synthetic Organic Chemical Manufacturing Industry
TOC = total organic compounds

The Applicant proposes to apply the LDAR program to 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). These areas were selected because they had the largest uncontrolled emissions for methanol, propylene, and H_2S. The following compounds were included as VOCs (not all compounds are found in the gas in each process area): methanol (CH_3OH), propylene (C_3H_6), COS, hydrogen cyanide (HCN), and methyl diethanolamine (MDEA).

Table 1 presents the annual fugitive emissions that were calculated for the Project.

Total Combined Facility-Wide Emissions

The total combined annual emissions from all emission sources of the Project are shown in Table 1, Total Combined Annual Criteria Pollutant Emissions.

Commissioning

The Project refinements consist of minor changes to operating schedules for the equipment. No changes to the commissioning schedule are expected to result from these revisions. Therefore, the commissioning emissions calculated and modeled in the Revised AFC accurately characterize the potential air quality impacts during commissioning with the Project refinements incorporated. As noted in the Amendment to the Revised AFC, PM_{10} emission rates are expected to be lower when commissioning the CTG/HRSG on hydrogen-rich fuel; therefore, the analysis in the Revised AFC provides a conservative overestimate. The Project refinements would not change the conclusions in Section 5.1 of the Revised AFC, and potential air quality impacts during construction are expected to remain less than significant.

Commissioning modeling was conducted to show compliance with the new federal 1-hour NO_2 standard. The modeling techniques are discussed in Section 3.1.3, and the results are presented in Section 3.1.4.

Greenhouse Gas Emissions

Total facility greenhouse gas emissions estimates were revised to incorporate Project refinements. These emissions are presented in Appendix B. The total onsite plant GHG emissions from both stationary and mobile sources are expected to be 529,911 metric tons (tonnes) per year.

The Project's GHG emissions will be approximately 500 pounds per megawatt hour (lb/MWh), well below the 1,100 lbs/MWh threshold requirement of Senate Bill 1368.

Operational Emissions – Mobile Sources – Onsite

Material Handling and Feedstock Delivery

No revisions were made to the operation or emissions from the handling of materials associated with the HECA Project.

Operations and Maintenance Vehicles

In response to CEC Set One Data Request Nos. 23 and 24, emissions from 10 light heavy-duty gasoline trucks and 10 light heavy-duty diesel trucks used for onsite maintenance were included in the modeling analyses. It was assumed that each vehicle would travel 10,000 miles per year, up to of 27 miles per day. Emissions from these trucks were estimated using emission factors from the EMFAC2007 model for year 2015 for light heavy-duty gasoline trucks and light heavy-duty diesel trucks driving 15 miles per hour. This is consistent with the technique used to estimate the onsite feedstock delivery truck emissions. Vehicle emissions are presented in Appendix A.

3.1.3 Dispersion Modeling

The purpose of the air quality impact analyses is to evaluate whether criteria pollutant emissions resulting from the Project will cause or contribute significantly to a violation of California or national Ambient Air Quality Standards (AAQS) or contribute significantly to degradation of air quality-related values in Class I areas. The air quality impact analyses were performed using the same model and model option selections, and receptor locations as in the Revised AFC and Amendment to the Revised AFC. Copies of the revised modeling files are included on the Revised Air Quality Modeling DVD, June 2010 included with this document.

Meteorological Data

The meteorological data set was updated at the request of the SJVAPCD. Data for the years 2004 to 2008 from the Bakersfield Airport meteorological station were used in the revised analyses presented in this document. This is the same meteorological station used for all previous analyses. These data were issued by the SJVAPCD and are provided on the Revised Air Quality Modeling DVD, June 2010.

Turbine Impact Screening Modeling

Turbine impact screening modeling was not revised. The stack parameters that were determined to be associated with these maximum predicted impacts from the screening modeling conducted for the Amendment to the Revised AFC were used in all subsequent simulations of the refined AERMOD analyses. These stack parameters were associated with Case 2C, 60 percent load burning natural gas and had the lowest exhaust temperature and exit velocity.

Refined Modeling

A refined modeling analysis was performed to estimate offsite criteria pollutant impacts from operational emissions of the Project. The CTG/HRSG was modeled assuming the worst-case emissions corresponding to each averaging time and the turbine stack parameters that were determined in the turbine screening analysis. The maximum mass emission rates that will occur for any averaging time, whether during turbine startups, normal operations, turbine shutdowns, or a combination of these activities, were used in all refined modeling analyses. Emissions from all Project sources, including the CO_2 vent, were included in the AERMOD modeling to ensure maximum impacts from the Project were examined.

Modeling for Compliance with NO_2 1-hour National Ambient Air Quality Standards

Applicant has been working with SJVAPCD to conduct the NO_2 modeling in a manner consistent with the new U.S. EPA NO_2 1-hour standard. SJVAPCD has developed techniques to conduct the NO_2 modeling analyses that have been approved by U.S. EPA Region 9. On April 12, 2010 SJVAPCD published the draft guidance document "Modeling Procedure to Address the New Federal 1 Hour NO_2 Standard." This guidance discusses a three-tier modeling approach and outlines the U.S. EPA criteria for determining appropriate background data. The tiered approach was developed to streamline the modeling process, with each tier requiring more refined modeling techniques. The SJVAPCD recommends the using the AERMOD model with either the ozone-limiting method (OLM) or plume volume molar ratio method (PVMRM) algorithm for all analyses. HECA used the OLM algorithm in the AERMOD NO_2 modeling analysis.

The Tier I analysis consists of combining the maximum 1-hour predicted NO_2 concentration from AERMOD with the 98^{th} percentile background concentration. In the guidance document, SJVACPD has determined the 98^{th} percentile background NO_2 concentration at all San Joaquin Valley monitoring stations for the years 2006 to 2008.

The Tier II analysis requires AERMOD to be run to predict the eighth highest 1-hour concentration for each year. The highest eighth high 1-hour concentration predicted for any year over the modeling period shall be combined with the 98^{th} percentile background NO_2 concentration to estimate the peak offsite NO_2 concentration.

The Tier III analysis requires that the modeling be conducted per the procedures outlined by U.S. EPA in "Notice Regarding Modeling for New Hourly NO_2 NAAQS", dated February 25, 2010. In this approach, AERMOD is run to produce an output file with NO_2 concentrations at every receptor for every hour in the meteorological data set using the hourly POSTFILE option. From the hourly AERMOD POSTFILE, the maximum 1-hour concentration for each day of the data period at each receptor is determined using a FORTRAN post-processing program designed for this purpose. The post–processor then determines the eighth highest daily maximum 1-hour concentration from the daily 1-hour maximum concentrations at each receptor for each year modeled. The eighth highest concentration is representative of the 98^{th} percentile concentration from the distribution of daily 1-hour maximum values. At each receptor, the eighth highest daily 1-hour maximum concentrations are averaged across the modeled years. The highest of the average eighth highest (98^{th} percentile) concentrations among the values for all receptors plus the 98^{th} percentile background NO_2 concentration from a representative monitoring location is used to represent the peak offsite NO_2 concentration for comparison with the National Ambient Air Quality Standards (NAAQS).

Through discussions with SJVAPCD modeling staff, a fourth-tier modeling analysis technique was developed. The Tier IV AERMOD modeling is conducted in the same manner as the Tier III AERMOD modeling to produce an output file with NO_2 concentrations at every receptor for every hour in the meteorological data set using the hourly POSTFILE option. Concurrent hourly NO_2 background data from the most representative monitoring station are then added to the modeled NO_2 concentrations to obtain the total NO_2 concentration for each hour. Then the 98^{th} percentile (eighth highest) of the daily maximum 1-hour concentrations for each year of meteorological data at each receptor are determined. The eighth highest daily 1-hour maximum concentrations at each receptor are then averaged across the five modeled years and the maximum of these averaged values from all receptors is used to represent the peak predicted offsite NO_2 concentration for comparison with the NAAQS.

The hourly monitoring NO_2 data used in the Tier IV analysis were provided by SJVAPCD. SJVAPCD provided hourly NO_2 data from the Bakersfield, California Avenue monitoring station for 2004 and from the Bakersfield Golden State Highway monitoring station for years 2005 to 2008. Data for 2004 at the Bakersfield Golden State Highway monitoring station had too many missing values to be considered a valid data set.

SJVAPCD has developed a protocol for filling in missing data that involves linearly interpolating data when one hour of data is missing. If data for two or more sequential hours are missing, the missing values are filled in with the highest recorded 1-hour NO_2 concentration from the appropriate calendar quarter. Although this technique is conservative, it overly skews the total concentration as the highest quarterly background concentration dominates the total impact. It was found that for more than 95 percent of all receptors, the filled-in background data dominated the total NO_2 concentration, thus causing the predicted NO_2 concentration to be significantly higher than expected if actual data were available for that hour.

A post-processor program was developed by URS to process the Tier III and IV AERMOD POSTFILE output files. The post-processor calculates the 98^{th} percentile of the daily maximum 1-hour concentrations for each year of meteorological data at each receptor. The post-processor has the option to add concurrent NO_2 background to the AERMOD output prior to calculating the 98^{th} percentile concentrations, which is consistent with the Tier IV analysis described above.

HECA has used the tiered analysis approach outlined above to show compliance with the new NO_2 1-hour standard. The maximum averaged 98^{th} percentile NO_2 concentration predicted for offsite receptors using any of the tiered analyses will be compared with the federal NO_2 1-hour standard of 100 parts per billion (ppb), which is equivalent to 188.68 micrograms per cubic meter ($\mu g/m^3$), to determine whether compliance will be achieved.

NO_2 emissions from construction activities and commissioning will also be modeled to show compliance wit the federal NO_2 1-hour standard.

3.1.4 Compliance with Ambient Air Quality Standards

Air dispersion modeling was performed according to the methodology described in Revised AFC Section 5.1.2.3 and Section 3.1.3 above. This was done to evaluate the maximum increase in ground level pollutant concentrations resulting from Project emissions based on the Project refinements, and to compare the maximum predicted impacts, including background pollutant levels, with applicable short-term and long-term California Ambient Air Quality Standards (CAAQS) and NAAQS.

Construction Impacts

Compliance with the federal 1-hour NO_2 standard was demonstrated using a Tier IV analysis as described in the modeling techniques above. The average of the 98^{th} percentile daily maximum 1-hour concentration for the years 2004 to 2008 was predicted to be 163 $\mu g/m^3$ (this value includes the background concentration). The predicted concentration is below the NAAQS of 188.68 $\mu g/m^3$ therefore emissions from construction activities are expected to have a less-than-significant impact.

Operations Impacts

The emissions used for each pollutant and averaging time are explained and quantified in Section 3.1.2, Operations.

Table 8, AERMOD Modeling Results for Project Operations (All Project Sources Combined), summarizes the maximum predicted criteria pollutant concentrations due to Project emissions. The incremental impacts of Project emissions will be below the federal Prevention of Significant Deterioration (PSD) Significant Impact Levels (SILs) for all attainment pollutants, despite the use of worst-case emissions scenarios for all pollutants and averaging times. Although maximum predicted values for PM_{10} are below the SILs, these thresholds do not apply to this pollutant because the San Joaquin Valley Air Basin is designated as being in non-attainment with respect to the federal ambient standards. No SILs have been established yet for $PM_{2.5}$.

Table 8 also shows that the modeled impacts due to the Project emissions, in combination with conservative background concentrations, will not cause a violation of any 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 non-attainment pollutants and their precursors will be offset to ensure a net air quality benefit.

Compliance with the federal 1-hour NO_2 standard was demonstrated using a Tier IV analysis as described in the modeling techniques above. The average of the 98^{th} percentile daily maximum 1-hour concentration for the years 2004 to 2008 is presented in Table 8, this value includes the background concentration.

The locations of predicted maximum impacts will vary by pollutant and averaging time. The peak 24-hour PM_{10} and $PM_{2.5}$ are predicted to occur on the southwestern boundary of the Project Site, while the peak annual NO_2, SO_2, PM_{10}, and $PM_{2.5}$ concentrations are predicted to occur on the eastern boundary of the Project Site.

The peak 1-hour NO_2 concentrations are predicted to occur approximately 4 kilometers southwest of the Project Site. Peak 1-hour, 3-hour, and 24-hour SO_2 concentrations are predicted to occur approximately 7.5 kilometers southeast, 3 kilometers south, and 5.5 kilometers west of the Project Site, respectively.

Carbon monoxide 1-hour impacts from the all sources including the CO_2 vent were predicted to be 2,180 $\mu g/m^3$ at a point off of the Project Site and Controlled Areas approximately 4.5 kilometers

Table 8
AERMOD Modeling Results for Project Operations (All Project Sources Combined)

Pollutant	Averaging Period	Model Predicted Concentration (µg/m³)	Class II Significance Level (µg/m³)	% of SIL	Background Conc. [4] (µg/m³)	Monitoring Station Description [4]	CAAQS (µg/m³)	NAAQS (µg/m³)	Total Conc. (µg/m³)
NO_2 [1]	1-hour (OLM) [1,3]	**133.71**	NA	NA	143.4	1	339	NA	277
	1-hour (OLM) [1,3] NAAQS	**176.98**	NA	NA	NA[2]	6	NA	188.68	177
	Annual (OLM) [1]	**0.66**	1	87%	39.6	1	57	100	40
CO	1-hour [3]	**2179.70**	2,000	71%	4,025	2	23,000	40,000	6,205
	8-hour [3]	**576.12**	500	43%	2,444	2	10,000	10,000	3,020
SO_2	1-hour [3]	**26.50**	NA	NA	340.6	3	655	NA	367
	3-hour [3]	**15.89**	25	31%	195	3	NA	1300	211
	24-hour [3]	**1.79**	5	18%	81.38	3	105	365	83
	Annual	**0.13**	1	14%	26.7	3	NA	80	27
PM_{10}	24-hour [3]	**4.08**	5	58%	267.4	4	50	150	-
	Annual	**0.57**	1	59%	56.5	4	20	Revoked	-
$PM_{2.5}$ [4]	24-hour [3]	**2.64**	-	44%	154	5	NA	35	-
	Annual	**0.41**	-	45%	25.2	5	12	15	-
H_2S	1-hour	**20.47**	NA	NA	NA	NA	42	NA	20

Source: HECA Project

Notes:

1 The Ozone Limiting Method (OLM) was applied using hourly O_3 data.
2 Background NO_2 concentrations are included in the federal NO_2 1-hour analysis.
3 For short-term (1-, 3-, 8-, and 24-hour) modeling, only one emergency generator will be operational at any one time, and the current assumption is that two gasifier heaters are expected to be operational at any one time.
4 Monitoring station for the maximum background concentration is described below:

1. CARB, Maximum of last three years (2006-2008), Bakersfield Golden State Highway, 2006
2. CARB, Maximum of last three years (2006-2008), Bakersfield Golden State Highway, 2007
3. CARB, Maximum of last three years (2006-2008), Bakersfield Golden State Highway, 2008
4. CARB, Maximum of last three years (2006-2008), Shafter-Walker Street, 2007
5. CARB, Maximum of last three years (2006-2008), Fresno – 1st Street, 2007
6. 98th percentile of daily 1-hour maximum concentrations averaged over last three years (2006-2008), Bakersfield Golden State Highway

CAAQS = California Ambient Air Quality Standards
CARB = California Air Resources Board
CO = carbon monoxide
H_2S = hydrogen sulfide
µg/m³ = micrograms per cubic meter
NA = not applicable.
NAAQS = National Ambient Air Quality Standards
NO_2 = nitrogen dioxide
OLM = ozone limiting method
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
PM_{10} = particulate matter less than 10 microns in diameter
SIL = Significant Impact Level
SO_2 = sulfur dioxide

southwest of the site, and 576 μg/m^3 for the 8-hour averaging time approximately 3 kilometers southwest of the site. These values are above the CO SIL. Since the predicted 1-hour and 8-hour CO concentrations plus background concentration are below the CAAQS and NAAQS, impacts from CO are less than significant.

Hydrogen sulfide impacts from the carbon dioxide vent and fugitive emissions were predicted to be 20 μg/m^3 at the maximum impact point off of the Project Site and Controlled Area approximately 3 kilometers southwest from the site. This value is below the 1-hour CAAQS of 42 μg/m^3.

Turbine Commissioning

Compliance with the federal 1-hour NO_2 standard was demonstrated using a Tier IV analysis as described in the modeling techniques above. The average of the 98th percentile daily maximum 1-hour concentration for years 2004 to 2008 from commissioning was predicted to be 184 μg/m^3. This value includes the background concentration. The predicted concentration is below the NAAQS of 188.68 μg/m^3; therefore, emissions from commissioning are expected to have a less-than-significant impact.

Impacts for Non-Attainment Pollutants and their Precursors

The emission offset program described in the SJVAPCD Rules and Regulations was developed to facilitate net air quality improvement when new sources locate within the District. Project impacts of non-attainment pollutants (PM_{10}, $PM_{2.5}$, and O_3) and their precursors (NO_X, SO_2, and VOC) will be fully mitigated by emission offsets. 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.

Effects on Visibility from Plumes

There will be no changes to the effects on visibility from plumes, since there are no changes to the cooling tower emissions due to Project refinements.

3.1.5 Impacts on Air Quality Related Value in Class I Areas

In response to U.S. Forest Service comments about the Class I area analyses, and to reflect emission changes due to Project refinements, the CALPUFF modeling analysis for impacts to Air Quality Related Values (AQRV) was updated. Appendix D contains the revised Class I Area analysis report, which includes a discussion of the emissions from each source and how the U.S. Forest Service comments are addressed in the revised analysis.

The objectives of the modeling were to demonstrate whether air emissions from the Project will cause or contribute to a PSD increment exceedance or cause a significant impact on visibility, regional haze, or sulfur or nitrogen deposition in any Class I area. Since the Project location has not changed, the same Class I area (San Rafael Wilderness Area) was included in the revised AQRV analysis. The CALMET data were not changed from previous analyses.

The PSD increment analysis for the San Rafael Wilderness Class I area is shown in Table 9, PSD Class I Increment Significance Analysis – CALPUFF Results. No Class I PSD increments will be exceeded.

Table 9
PSD Class I Increment Significance Analysis – CALPUFF Results

Class I Area	Pollutant Unit Threshold	Annual NO_x µg/m^3 0.1	3-hour SO_2 µg/m^3 1	24-hour SO_2 µg/m^3 0.2	Annual SO_2 µg/m^3 0.08	24-hour PM_{10} µg/m^3 0.32	Annual PM_{10} Annual 0.16
San Rafael Wilderness Area	2001	3.93E-03	2.34E-01	5.27E-02	7.36E-04	8.70E-02	3.33E-03
	2002	4.27E-03	2.46E-01	5.05E-02	8.65E-04	7.72E-02	3.80E-03
	2003	4.44E-03	2.70E-01	4.42E-02	8.71E-04	9.33E-02	3.78E-03
Exceed?		No	No	No	No	No	No

Source: HECA Project

Notes:

µg/m^3 = micrograms per cubic meter
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SO_2 = sulfur dioxide

Effects on Visibility. This revised analysis was conducted using the same model (CALPUFF). The same 3-year meteorological data set for 2001 to 2003 was used in the revised analysis.

Visibility impact results for the San Rafael Wilderness Class I area are shown in Table 10, Visibility Analysis – CALPUFF Results. No maximum extinction change exceeds 10 percent with only 1 to 3 days of exceedance of 5 percent despite the conservative operating emission scenario. Therefore, the Project successfully passed all screening criteria.

Table 10
Visibility Analysis – CALPUFF Results

Class I Area	Pollutant Unit Threshold	No. of Days > 5% Days 0	No. of Days >10% Days 0	Maximum Extinction Change % 10	Day of Maximum Extinction Change Julian Day
San Rafael Wilderness Area	2001	3	0	9.48	308
	2002	4	0	8.07	287
	2003	2	0	6.65	247
Exceed?				No	

Source: HECA Project.

Terrestrial Resources. This revised analysis was conducted using the same model (CALPUFF). Table 11, Total Nitrogen and Sulfur Deposition Analysis – CALPUFF Results, summarizes the maximum modeled impacts versus the National Park Service and the U.S. Forest Service significance criteria. All impacts are below the significance criteria.

Table 11
Total Nitrogen and Sulfur Deposition Analysis – CALPUFF Results

Class I Area	**Pollutant Unit Threshold**	**Deposition Nitrogen $g/m^2/s$ 1.59E-11**	**Deposition Sulfur $g/m^2/s$ 1.59E-11**
San Rafael Wilderness Area	2001	9.75E-13	3.85E-13
	2002	1.23E-12	5.04E-13
	2003	1.25E-12	4.54E-13
Exceed?		No	No

Source: HECA Project
Notes:
$g/m^2/s$ = grams per square meter per second.

Aquatic Resources. A significant effect of NO_X and SO_2 emissions on aquatic resources is nitrogen and sulfur deposition and subsequent acidification. However, because any increased nitrogen and sulfur deposition due to the Project will be minimal, impacts to water acid neutralizing capacity and pH, and, therefore, acidification or eutrophication, are not likely to occur.

The revised CALPUFF air impact modeling analysis for Class I areas is presented in selected revised tables, provided in Appendix D.

3.2 PUBLIC HEALTH

3.2.1 Construction Emissions

The Project refinements would not result in a change to construction emissions; therefore, there is no change to the construction impact analysis that was previously conducted. In the response to CEC Set One Data Request No. 85, the health risks due to diesel particulate matter (DPM) concentration from construction equipment were examined and found to be less than significant.

3.2.2 Operations Emissions

The Project refinements would cause a slight increase in emissions of TACs during operation than those presented in the response to CEC Set One Data Request No. 86. Therefore, a revised Health Risk Assessment (HRA) was conducted.

The HRA presented in this document was conducted using the same techniques and emission factors outlined in the Revised AFC and responses to CEC Data Requests.

The Project refinements that changed TAC emissions from those presented in the response to CEC Set One Data Request Nos. 86 through 90 are outlined below. TAC emissions and calculation techniques for all sources are presented in Appendix C.

CTG/HRSG

No modification to TAC emissions for the CTG/HRSG are needed, because full load operations for 8,322 hours were already considered while burning syngas.

Gasification Flare

Additional flaring was added to account for the offline turbine washes. The maximum hourly emissions were based on 1,695 MMBtu/hr of syngas flaring and the maximum annual emissions were based on 196,600 MMBtu/yr of flaring.

SRU Flare

To more accurately account for the time expected to startup the gasifier, the SRU flare may flare for up to 40 hours per year, this is an increase from 6 hours per year previously proposed in the Revised AFC. Annual emissions are based on 40 hours of operation.

Rectisol Flare

No revisions were made to the operation or emissions from the rectisol flare. The rectisol flare operation remains for emergency purposes only.

Gasifier Refractory Heaters

Each of the three gasifier refractory heaters operate at 18 MMBtu/hr, firing natural gas for 1,200 hours per year each. Hourly emissions are based on the operation of two heaters and annual emissions are based on the operation of all three heaters for 1,200 hours each.

Auxiliary Boiler

The hours of operation associated with the auxiliary boiler did not change due to the Project refinements, although due to the use of SCR, ammonia will now be emitted from the auxiliary boiler. Ammonia slip will be limited to 5 ppmv at 3 percent O_2 or 0.0022 lb/MMBtu or 0.31 lb/hr.

Tail Gas Thermal Oxidizer

No refinements were made to the emissions estimated for the Tail Gas Thermal Oxidizer, since the emissions are based on 8,760 hours per year of 10 MMBtu/hr natural gas assist gas.

CO_2 Vent

Project engineering refinement determined that the concentration of COS in the CO_2 stream is not expected to exceed 43 ppmv; thus, the COS emissions from the emergency CO_2 venting will be reduced. Although COS is a hazardous air pollutant, it does not have an associated Office of Environmental Health Hazard Assessment health risk; thus, emissions from the CO_2 vent did not change in the HRA modeling.

Diesel Emergency Generators

The maintenance operation schedule was changed to 52 hours per year for each engine. The DPM emission factors for U.S. EPA Offroad Tier 4 engines used in the response to CEC Set One Data Request Nos. 30 and 86 were used in this HRA.

Diesel Emergency Fire Water Pump

The DPM emission factors for U.S. EPA Offroad Tier 4 engines used in the response to CEC Set One Data Request Nos. 30 and 86 were used in this HRA; therefore, there is no change to the emissions from the fire pump engine.

Fugitive Emissions

In response to CEC Set One Data Request Nos. 17 and 89, emissions from fugitive leaks in the piping and components were included in the total facility inventory. These emissions have not changed due to the Project refinements described in this document. TACs included in the HRA from the fugitive emissions include H_2S, methanol, propylene, hydrogen cyanide, and ammonia.

Cooling Towers

No revisions were made to the operation or emissions from the cooling towers.

Material Handling and Feedstock Delivery

No revisions were made to the operation or emissions from the handling of materials associated with the HECA Project.

Operations and Maintenance Vehicles

DPM Emissions from the 10 light heavy-duty diesel trucks used for onsite maintenance were included in the HRA. The DPM emissions were estimated using EMFAC2007 for fleet year 2040. A described in the Revised AFC, this is a representative vehicle fleet year, to characterize the 70-year cancer risk.

3.2.3 HRA Modeling

The HRA was conducted using the same techniques described in the Revised AFC and response to CEC Set One Data Request No. 86. The AERMOD model was run for all sources with unit emission rate (1 g/s). Using HARP On-Ramp, the output from AERMOD and the source emissions were converted into a format for input into the HARP model. The HARP was run to predict the acute and chronic health index and the cancer risk.

As described in the response to CEC Set One Data Request No. 86, the AERMOD/HARP modeling included all grid receptors used in the criteria pollutant modeling, the sensitive receptor located at the Elk Hills School in Tupman, the residence along the northwestern property boundary, the residence at the intersection of Station Road and Tule Park Road, plus one offsite worker at the Tule Elk State Reserve ranger station, approximately 1 kilometer east of the property boundary.

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).

At the request of SJVAPCD, the meteorological data set was updated to include years 2004 to 2008 from the Bakersfield Airport meteorological station, which is consistent with the criteria pollutant analysis. These data were issued by SJVAPCD and are provided on the Revised Air Quality Modeling DVD, June 2010 along with all HRA modeling files.

3.2.4 HRA Model Results

The results of the HRA for Project operations are presented below in Table 12 for the point of maximum impact (PMI) and at the MEIW outside the property boundary and the maximally exposed individual resident (MEIR). The MEIR for all health risks occurs at the residence along the northwestern property boundary. The health risks at the residence at the intersection of Station Road and Tule Park Road are also shown for informational purposes in Table 12. 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 on a DVD with this document. The files include the Chi/Q in $\mu g/m^3$ per gram per second from each source at each receptor.

Table 12
Estimated Cancer Risk, Acute and Chronic Non-Cancer Total Hazard Index
Due to HECA Operations

Location	Cancer Risk	Chronic Hazard Index	Acute Hazard Index
Point of maximum impact	3.45 excess risk in 1 million	0.31 total hazard index	0.81 total hazard index
Coordinates of PMI in UTM NAD83 (m)	283,960E 3,911,650N	283,960E 3,911,650N	282,362E 3,912,769N
Peak risk at off-site worker MEIW	0.52 excess risk in 1 million	0.05 total hazard index	0.25 total hazard index
Coordinates of MEIW in UTM NAD83 (m) (Tule Elk State Reserve Ranger Station)	285,170E 3,912,389N	285,170E 3,912,389N	285,170E 3,912,389N
Peak risk at MEIR	0.95 excess risk in 1 million	0.06 total hazard index	0.64 total hazard index
Coordinates of MEIR in UTM NAD83 (m) (Residence at the northwest corner of the property)	282,408 E 3,913,181 N	282,408 E 3,913,181 N	282,408 E 3,913,181 N
Risk at Residence at Station Road and Tule Park Road	0.70 excess risk in 1 million	0.06 total hazard index	0.36 total hazard index
Coordinates in UTM NAD83 (m) (Residence at Station Road and Tule Park Road)	284,396 E 3,912,529 N	284,396 E 3,912,529 N	284,396 E 3,912,529 N
Peak risk at nearest Sensitive Receptor (Elk Hills School, Tupman, California)	0.48 excess risk in 1 million	0.04 total hazard index	0.11 total hazard index
Coordinates of Sensitive Receptor NAD83 (m)	285,878E 3,908,605N	285,878E 3,908,605N	285,878E 3,908,605N
Significance threshold	10 in 1 million	1	1
Below significance?	Yes	Yes	Yes

Source: HECA Project

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
NAD83 = Geographic coordinate system North American datum 83
PMI = point of maximum impact
UTM = Universal Transverse Mercator

SJVAPCD (San Joaquin Valley Air Pollution Control District), 2010. Draft Modeling Procedure to Address the New Federal 1 Hour NO_2 Standard. April 12, 2010.

URS Corporation, 2009. Revised Application for Certification for Hydrogen Energy California, Kern County, California. Prepared for Hydrogen Energy International LLC. May 2009.

U.S. EPA (U.S. Environmental Protection Agency), 1992. *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised*. EPA-454/R-92-019. October 1992.

U.S. EPA (U.S. Environmental Protection Agency), 1995. Guidance, *Protocol for Equipment Leak Emission Estimates*. EPA-453/R-95-017. November 1995.

U.S. EPA (U.S. Environmental Protection Agency), 2010. Notice Regarding Modeling for New Hourly NO_2 NAAQS. February 25, 2010.

APPENDIX A
HECA OPERATIONAL CRITERIA EMISSIONS

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Pollutant	Total Annual	CTG/HRSG Maximum (1)	Cooling Towers (2)	Auxiliary Boiler	Emergency Generators (3)	Fire Water Pump	Gasification Flare	SRU Flare	Rectisol Flare	Tail Gas Thermal Oxidizer	CO_2 Vent	Gasifier Refractory Heaters	Feedstock (4)	Fugitives
	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)
NO_X	195.1	168.0	--	0.9	0.2	0.1	7.2	0.2	0.2	10.5	--	7.8	--	--
CO	406.9	155.7	--	5.8	0.9	0.2	111.2	0.2	0.1	8.8	106.9	11.3	--	6.0
VOC	59.1	33.8	--	0.6	0.10	0.01	0.003	0.003	0.002	0.3	2.4	2.3	--	19.7
SO_2	37.7	28.3	--	0.3	0.001	0.0003	0.118	0.372	0.003	8.5	--	0.07	--	--
PM_{10}	111.4	82.3	24.1	0.8	0.02	0.001	0.007	0.006	0.004	0.4	--	0.3	3.6	--
$PM_{2.5}$ (5)	99.2	82.3	14.5	0.8	0.02	0.001	0.007	0.006	0.004	0.4	--	0.3	1.0	--
NH_3	76.3	75.8	--	0.3	--	--	--	--	--	--	--	--	--	0.2
H_2S	3.7	--	--	--	--	--	--	--	--	--	1.3	--	--	2.4

(1) Total annual CTG/HRSG emissions represent the maximum emissions rate from firing either hydrogen-rich fuel, natural gas or co-firing.
(2) Includes contributions from all three cooling towers
(3) Includes contributions from both emergency generators
(4) Feedstock emissions are shown as the contribution of all dust collection points.
(5) Where $PM_{10} = PM_{2.5}$, it is assumed that PM_{10} is 100% $PM_{2.5}$
(6) CO_2e emission rates are shown as metric tons (tonnes)

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Summary of CTG/HRSG Emission Rates Under the Three Different Firing Scenarios

Average Annual Emissions per Turbine	CTG/HRSG - Nat Gas (ton/yr/CT)	CTG/HRSG - Syn Gas (ton/yr/CT)	CTG/HRSG - Co Firing (ton/yr/CT)	Maximum (ton/yr/CT)
NO_X	148.8	168.0	167.8	168.0
CO	141.2	105.9	155.7	155.7
VOC	30.5	19.6	33.8	33.8
SO_2	20.5	28.3	24.7	28.3
$PM_{10} = PM_{2.5}$	74.9	82.3	82.3	82.3
NH_3	66.9	75.8	75.7	75.8

Modeling Worst-Case 1 hr Emissions per Turbine	CTG/HRSG - Nat Gas (g/sec/CT)	CTG/HRSG - Syn Gas (g/sec/CT)	CTG/HRSG - Co Firing (g/sec/CT)	Maximum (g/sec/CT)
NOx	21.0	21.0	21.0	21.0
CO	211.6	211.6	211.6	211.6
SO_2	0.7	0.86	0.80	0.9

Modeling Worst-Case 3 hr Emissions per Turbine	CTG/HRSG - Nat Gas (g/sec/CT)	CTG/HRSG - Syn Gas (g/sec/CT)	CTG/HRSG - Co Firing (g/sec/CT)	Maximum (g/sec/CT)
SO_2	0.7	0.86	0.80	0.9

Modeling Worst-Case 8 hr Emissions per Turbine	CTG/HRSG - Nat Gas (g/sec/CT)	CTG/HRSG - Syn Gas (g/sec/CT)	CTG/HRSG - Co Firing (g/sec/CT)	Maximum (g/sec/CT)
CO	89.1	88.6	89.3	89.3

Modeling Worst-Case 24 Hour Emission Rate	CTG/HRSG - Nat Gas (g/sec/CT)	CTG/HRSG - Syn Gas (g/sec/CT)	CTG/HRSG - Co Firing (g/sec/CT)	Maximum (g/sec/CT)
SO_2	0.7	0.86	0.80	0.9
$PM_{10} = PM_{2.5}$	2.3	2.5	2.5	2.5

Modeling Annual Average Emission Rate per Turbine	CTG/HRSG - Nat Gas (g/sec/CT)	CTG/HRSG - Syn Gas (g/sec/CT)	CTG/HRSG - Co Firing (g/sec/CT)	Maximum (g/sec/CT)
NO_X	4.3	4.8	4.8	4.8
CO	4.1	3.0	4.5	4.5
VOC	0.9	0.6	1.0	1.0
SO_2	0.6	0.82	0.71	0.8
$PM_{10} = PM_{2.5}$	2.2	2.4	2.4	2.4

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CTG Operating Parameters

Ambient Temperature	UNITS	Winter Minimum - 20°F				Yearly Average- 65°F				Summer Maximum - 97°F			
CTG Load Level	Percent Load (%)	100%	100%	80%	60%	100%	100%	80%	60%	100%	100%	80%	60%
Evap Cooling Status	off / on	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Duct Burner Status	off / on	On	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off

Average Emission Rates from CTG (lbs/hr/turbine) - Normal Operation

	UNITS	Winter Minimum - 20°F				Yearly Average- 65°F				Summer Maximum - 97°F			
NO_x (@ 4.0 ppm)	lbm/hr	37.2	29.0	24.8	20.8	35.1	27.0	23.1	19.4	34.2	26.1	22.4	18.7
CO (@ 5.0 ppm)	lbm/hr	28.3	22.1	18.8	15.8	26.7	20.5	17.6	14.8	26.0	19.8	17.0	14.2
VOC (@ 2.0 ppm)	lbm/hr	6.5	5.0	4.3	3.6	6.1	4.7	4.0	3.4	5.9	4.5	3.9	3.2
SO_2 (@ 12.65 ppmv)	lbm/hr	5.2	4.1	3.5	3.0	4.9	3.8	3.3	2.8	4.8	3.7	3.2	2.7
$PM_{10} = PM_{2.5}$	lbm/hr	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
NH_3 (@ 5.0 ppm slip)	lbm/hr	17.2	13.4	11.4	9.6	16.2	12.5	10.7	9.0	15.8	12.1	10.3	8.6

All turbine operating parameters and emissions data provided by FLUOR based on expected operating parameters.

Startup / Shutdown Emissions from Turbine (1CT)

Cold Startup			Hot Startup			Shutdown		
180 (min. in cold startup)	Max 1-hr. (lb/hr)	Total (lb/180min)	60 (min. in hot startup)	Max 1-hr. (lb/hr)	Total (lb/60min)	30 (min. in shutdown)	Max 1-hr. (lb/hr)	Total (lb/30min)
NO_X	90.7	272.0	NOx	167.0	167.0	NOx	62.0	62.0
CO	1,679.7	5,039.0	CO	394.0	394.0	CO	126.0	126.0
VOC	266.7	800.0	VOC	98.0	98.0	VOC	21.0	21.0
SO_2 (@ 12.65 ppmv)	5.1	15.3	SO_2	5.1	5.1	SO_2	2.6	2.6
$PM_{10} = PM_{2.5}$	19.0	57.0	$PM_{10} = PM_{2.5}$	19.8	19.8	$PM_{10} = PM_{2.5}$	5.0	5.0

All turbine operating parameters and emissions data provided by FLUOR based on expected operating parameters.
Startup and shutdown SO_2 emissions will always be lower than normal operation max SO_2 emissions. Startup and shutdown emissions are assumed equal to the normal operations max emission rate.

Average Annual Emissions

			Pollutant	Turbine Emissions lb/yr/CT	Emissions ton/yr/CT	Emissions g/sec/CT
Total Hours of Operation	8,322.0					
Total Number of Cold Starts	10.0					
Cold Start Duration (hr)	3.0		NO_X	297,638.3	148.8	4.3
Total Number of Hot Starts	20.0		CO	282,487.8	141.2	4.1
Hot Start Duration (hr)	1.0		VOC	60,975.8	30.5	0.9
Total Number of Shutdowns	30.0		SO_2	40,902.9	20.5	0.6
Shutdown Duration (hr)	0.5		$PM_{10} = PM_{2.5}$	149,742.0	74.9	2.2
Duct Burner Operation (hr)	8,257.0		NH_3	133,837.3	66.9	1.9
Average Normal Operation (hr)	0.0					

Assumptions:
Average annual normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

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First Quarter Emissions (Jan, Feb, Mar)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	74,409.6	37.2
Total Number of Hot Starts	5.0	CO	70,622.0	35.3
Hot Start Duration (hr)	1.0	VOC	15,243.9	7.6
Total Number of Shutdowns	7.5	SO_2	10,225.7	5.1
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	37,435.5	18.7
Duct Burner Operation (hr)	2,064.3	NH_3	33,459.3	16.7
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Second Quarter Emissions (Apr, May, Jun)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	74,409.6	37.2
Total Number of Hot Starts	5.0	CO	70,622.0	35.3
Hot Start Duration (hr)	1.0	VOC	15,243.9	7.6
Total Number of Shutdowns	7.5	SO_2	10,225.7	5.1
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	37,435.5	18.7
Duct Burner Operation (hr)	2,064.3	NH_3	33,459.3	16.7
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Modeling Worst-Case 1 hr Emissions per Turbine

Pollutant	lb/hr/CT	g/sec/CT
NOx	167.0	21.0
CO	1,679.7	211.6
SO_2	5.2	0.7

Assumptions:
Startup emissions represent worst case hr for NOx and CO.
Worst case 1 hr NOx emissions are from hot start
Worst case 1 hr CO emissions are from cold start
Calculation assumes that startup and shutdown SO_2 emissions will always be lower than normal operational max SO_2 emissions.

Third Quarter Emissions (Jul, Aug, Sep)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	74,409.6	37.2
Total Number of Hot Starts	5.0	CO	70,622.0	35.3
Hot Start Duration (hr)	1.0	VOC	15,243.9	7.6
Total Number of Shutdowns	7.5	SO_2	10,225.7	5.1
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	37,435.5	18.7
Duct Burner Operation (hr)	2,064.3	NH_3	33,459.3	16.7
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Fourth Quarter Emissions (Oct, Nov, Dec)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	74,409.6	37.2
Total Number of Hot Starts	5.0	CO	70,622.0	35.3
Hot Start Duration (hr)	1.0	VOC	15,243.9	7.6
Total Number of Shutdowns	7.5	SO_2	10,225.7	5.1
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	37,435.5	18.7
Duct Burner Operation (hr)	2,064.3	NH_3	33,459.3	16.7
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

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Modeling Worst-Case 3 hr Emissions per Turbine

	hr	emission rate lb/hr	Emissions lb/CT	
Total Hours of Operation	3.0			
Startup Duration	0.0		0.0	contribution over 3 hr from start up
Shutdown Duration	0.0		0.0	contribution over 3 hr from shut down
Hours of Normal Operation (burning natural gas)	3.0	5.2	15.6	contribution over 3 hr from normal operation
SO_2 worst-case 3 hr emissions per turbine	15.6	lb/3 hr		
SO_2 worst-case 1 hr emissions per turbine	5.2	lb/hr		
SO_2 modeling worst-case emissions per turbine	0.7	g/sec		

Assumptions:
Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
Normal operation assumes max emission rate
Worst-case 3 hr emissions assumes a total start up of : 0
Worst-case 3 hr emissions assumes a total shut down of : 0
Calculation assumes that startup and shutdown SO_2 emissions will always be lower than normal operational max SO_2 emissions

Modeling Worst-Case 8 hr Emissions per Turbine

	hr	emission rate lb/hr	Emissions lb/CT	
Total Hours of Operation	8.0			
Startup Duration (1 cold start and 1 hot start)	4.0		5,433.0	contribution over 8 hr from start up (1 cold & 1 hot)
Shutdown Duration	0.5		126.0	contribution over 8 hr from shut down
Hours of Normal Operation (burning natural gas)	3.5	28.3	99.0	contribution over 8 hr from normal operation
CO worst-case 8 hr emissions per turbine	5,658.0	lb/8 hr		
CO worst-case 1 hr emissions per turbine	707.2	lb/hr		
CO modeling worst-case emissions per turbine	89.1	g/sec		

Assumptions:
Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Normal operation assumes max emission rate
Worst-case 8 hr emissions assumes a total COLD start up of : 1
Worst-case 8 hr emissions assumes a total HOT start up of : 1
Worst-case 8 hr emissions assumes a total shut down of : 1

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Worst-Case Daily Emissions per Turbine and Modeling Worst-Case 24 Hour Emission Rate

SO_2 (lb/day/CT)	124.9
SO_2 (g/s/CT) (burning natural gas)	0.7
$PM_{10} = PM_{2.5}$ (lb/day/CT)	432.0
$PM_{10} = PM_{2.5}$ (g/s/CT) (burning natural gas)	2.3

Assumptions:
Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.
For SO_2 24 hrs of normal operation at max emission rate
For PM emissions are calculated below assuming startup and shutdown contributions.

Worst-Case Daily Emissions per Turbine and Modeling Worst-Case 24 Hour Emission Rate

Pollutant	Time in Cold Startup hr	Startup Emission Rate lb/start	Time in Hot Startup hr	Startup Emission Rate lb/start	Time in Shut Down hr	Shutdown Emission Rate lb/shutdown	Time in Normal Operation hr	Normal Operation Emission Rate lb/hr	Worst-Case Daily Emissions lb/day/CT	Modeling Worst-Case 24 Hr Emission g/s/CT
Nox (1 COLD start up, 1 HOT start up, and I shut down)	3.0	272.0	1.0	167.0	0.5	62.0	19.5	37.2	1,225.6	6.4
CO	3.0	5,039.0	1.0	394.0	0.5	126.0	19.5	28.3	6,110.3	
VOC	3.0	800.0	1.0	98.0	0.5	21.0	19.5	6.5	1,045.0	
SO_2	3.0	15.3	1.0	5.1	0.5	2.6	19.5	5.2	124.5	0.7
$PM_{10} = PM_{2.5}$	3.0	57.0	1.0	19.8	0.5	5.0	19.5	18.0	432.8	2.3

Assumptions:
For NOx, CO, VOC, and PM -- emissions are calculated assuming:
Worst-case daily emissions assumes a total COLD start up of : 1 and a total HOT start up of: 1
Worst-case daily emissions assumes a total shut down of : 1
Remainder of time is spent at maximum normal operation emissions
See above calculation for worst-case daily SO_2:calculated as 24 hrs of normal operation at max emissions rate

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CTG Operating Parameters

Ambient Temperature	UNITS	Winter Minimum - 20°F				Yearly Average- 65°F				Summer Maximum - 97°F			
CTG Load Level	Percent Load (%)	100%	100%	80%	60%	100%	100%	80%	60%	100%	100%	80%	60%
Evap Cooling Status	off / on	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Duct Burner Status	off / on	On	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off

Average Emission Rates from CTG (lbs/hr/turbine) - Normal Operation

	UNITS	Winter Minimum - 20°F				Yearly Average- 65°F				Summer Maximum - 97°F			
NO_x (@ 4.0 ppm)	lbm/hr		37.2	31.5	26.1	39.7	36.9	31.0	25.6	39.7	38.0	30.9	25.6
CO (@ 3.0 ppm)	lbm/hr		17.0	14.4	11.9	18.1	16.8	14.1	11.7	18.1	17.4	14.1	11.7
VOC (@ 1.0 ppm)	lbm/hr		3.2	2.7	2.3	3.5	3.2	2.7	2.2	3.5	3.3	2.7	2.2
SO_2 (@ 5.0 ppmv)	lbm/hr		6.1	5.2	4.4	6.8	6.1	5.1	4.3	6.8	6.0	5.1	4.3
$PM_{10} = PM_{2.5}$	lbm/hr		19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8
NH_3 (@ 5.0 ppm slip)	lbm/hr		17.2	14.6	12.0	18.4	17.0	14.3	11.8	18.4	17.6	14.3	11.8

All turbine operating parameters and emissions data provided by FLUOR based on expected operating parameters.

Startup / Shutdown Emissions from Turbine (1CT)

Cold Startup			Hot Startup			Shutdown		
180 (min. in cold startup)	Max 1-hr. (lb/hr)	Total (lb/180min)	60 (min. in hot startup)	Max 1-hr. (lb/hr)	Total (lb/60min)	30 (min. in shutdown)	Max 1-hr. (lb/hr)	Total (lb/30min)
NO_X	90.7	272.0	NOx	167.0	167.0	NOx	62.0	62.0
CO	1,679.7	5,039.0	CO	394.0	394.0	CO	126.0	126.0
VOC	266.7	800.0	VOC	98.0	98.0	VOC	21.0	21.0
SO_2 (@ 12.65 ppmv)	5.1	15.3	SO2	5.1	5.1	SO2	2.6	2.6
$PM_{10} = PM_{2.5}$	19.0	57.0	$PM_{10} = PM_{2.5}$	19.8	19.8	$PM_{10} = PM_{2.5}$	5.0	5.0

All turbine operating parameters and emissions data provided by FLUOR based on expected operating parameters.
CTGs will always be started burning natural gas. Startup and shutdown emission rates above reflect natural gas.
Startup and shutdown SO_2 emissions will always be lower than normal operation max SO_2 emissions. Startup and shutdown emissions are assumed equal to normal operations (burning natural gas) at the max emission rate.

Average Annual Emissions

			Pollutant	Turbine Emissions lb/yr/CT	Emissions ton/yr/CT	Emissions g/sec/CT
Total Hours of Operation	8,322.0					
Total Number of Cold Starts	10.0					
Cold Start Duration (hr)	3.0		NO_X	336,046.9	168.0	4.8
Total Number of Hot Starts	20.0		CO	211,847.1	105.9	3.0
Hot Start Duration (hr)	1.0		VOC	39,122.8	19.6	0.6
Total Number of Shutdowns	30.0		SO_2	56,688.7	28.3	0.8
Shutdown Duration (hr)	0.5		$PM_{10} = PM_{2.5}$	164,604.6	82.3	2.4
Duct Burner Operation (hr)	8,257.0		NH_3	151,580.4	75.8	2.2
Average Normal Operation (hr)	0.0					

Assumptions:
Average annual normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

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First Quarter Emissions (Jan, Feb, Mar)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	84,011.7	42.0
Total Number of Hot Starts	5.0	CO	52,961.8	26.5
Hot Start Duration (hr)	1.0	VOC	9,780.7	4.9
Total Number of Shutdowns	7.5	SO_2	14,172.2	7.1
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	41,151.2	20.6
Duct Burner Operation (hr)	2,064.3	NH_3	37,895.1	18.9
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Second Quarter Emissions (Apr, May, Jun)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/yr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	84,011.7	42.0
Total Number of Hot Starts	5.0	CO	52,961.8	26.5
Hot Start Duration (hr)	1.0	VOC	9,780.7	4.9
Total Number of Shutdowns	7.5	SO_2	14,172.2	7.1
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	41,151.2	20.6
Duct Burner Operation (hr)	2,064.3	NH_3	37,895.1	18.9
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Modeling Worst-Case 1 hr Emissions per Turbine

Pollutant	lb/hr/CT	g/sec/CT
NOx	167.0	21.0
CO	1,679.7	211.6
SO_2	6.8	0.9

Assumptions:
Startup emissions represent worst case hr for NOx and CO. Startup and shutdown only burn natural gas.
NOx emissions are from hot start
CO emissions are from cold start
Normal operation burning syngas represents worst case SO_2
Calculation assumes that startup and shutdown SO_2 emissions will always be lower than normal operational (burning natural gas) max SO_2 emissions.

Third Quarter Emissions (Jul, Aug, Sep)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	84,011.7	42.0
Total Number of Hot Starts	5.0	CO	52,961.8	26.5
Hot Start Duration (hr)	1.0	VOC	9,780.7	4.9
Total Number of Shutdowns	7.5	SO_2	14,172.2	7.1
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	41,151.2	20.6
Duct Burner Operation (hr)	2,064.3	NH_3	37,895.1	18.9
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Fourth Quarter Emissions (Oct, Nov, Dec)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	84,011.7	42.0
Total Number of Hot Starts	5.0	CO	52,961.8	26.5
Hot Start Duration (hr)	1.0	VOC	9,780.7	4.9
Total Number of Shutdowns	7.5	SO_2	14,172.2	7.1
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	41,151.2	20.6
Duct Burner Operation (hr)	2,064.3	NH_3	37,895.1	18.9
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

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Modeling Worst-Case 3 hr Emissions per Turbine

	hr	Emission Rate lb/hr	Emissions lb/CT	
Total Hours of Operation	3.0			
Startup Duration	0.0		0.0	contribution over 3 hr from start up
Shutdown Duration	0.0		0.0	contribution over 3 hr from shut down
Hours of Normal Operation (burning syngas)	3.0	6.8	20.5	contribution over 3 hr from normal operation
SO_2 worst-case 3 hr emissions per turbine	20.5	lb/3 hr		
SO_2 worst-case 1 hr emissions per turbine	6.8	lb/hr		
SO_2 modeling worst-case emissions per turbine	0.9	g/sec		

Assumptions:
Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
Normal operation burning syngas represents worst case SO_2.
Worst-case 3 hr emissions assumes a total start up of : 0
Worst-case 3 hr emissions assumes a total shut down of : 0
Calculation assumes that startup and shutdown SO_2 emissions will always be lower than normal operational (burning natural gas) SO_2 emissions.

Modeling Worst-Case 8 hr Emissions per Turbine

	hr	Emission Rate lb/hr	Emissions lb/CT	
Total Hours of Operation	8.0			
Startup Duration (1 cold start and 1 hot start)	4.0		5,433.0	contribution over 8 hr from start up
Shutdown Duration	0.5		126.0	contribution over 8 hr from shut down
Hours of Normal Operation (burning syngas)	3.5	18.1	63.5	contribution over 8 hr from normal operation
CO worst-case 8 hr emissions per turbine	5,622.5	lb/8 hr		
CO worst-case 1 hr emissions per turbine	702.8	lb/hr		
CO modeling worst-case emissions per turbine	88.6	g/sec		

Assumptions:
Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Normal operation assumes max rate.
Worst-case 8 hr emissions assumes a total COLD start up of : 1
Worst-case 8 hr emissions assumes a total HOT start up of : 1
Worst-case 8 hr emissions assumes a total shut down of : 1

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Worst-Case Daily Emissions per Turbine and Modeling Worst-Case 24 Hour Emission Rate

SO_2 (lb/day/CT)	163.8
SO_2 (g/s/CT) (burning syngas)	0.9
$PM_{10} = PM_{2.5}$ (lb/day/CT)	475.2
$PM_{10} = PM_{2.5}$ (g/s/CT) (burning syngas)	2.5

Assumptions:
Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.
For SO_2 24 hrs of normal operation max emission rate
For PM 24 hrs of normal operation max emission rate

Worst-Case Daily Emissions per Turbine and Modeling Worst-Case 24 Hour Emission Rate

Pollutant	Time in Cold Startup hr	Startup Emission Rate lb/start	Time in Hot Startup hr	Startup Emission Rate lb/start	Time in Shut Down hr	Shutdown Emission Rate lb/shutdown	Time in Normal Operation hr	Normal Operation Emission Rate lb/hr	Worst-Case Daily Emissions lb/day/CT	Modeling Worst-Case 24 Hr Emission g/s/CT
NOx	3.0	272.0	1.0	167.0	0.5	62.0	19.5	39.7	1,275.9	6.7
CO	3.0	5,039.0	1.0	394.0	0.5	126.0	19.5	18.1	5,912.8	
VOC	3.0	800.0	1.0	98.0	0.5	21.0	19.5	3.5	986.4	
SO_2	3.0	15.3	1.0	5.1	0.5	2.6	19.5	6.8	156.1	0.8
$PM_{10} = PM_{2.5}$	3.0	57.0	1.0	19.8	0.5	5.0	19.5	19.8	467.9	2.5

Assumptions:
For NOx, CO, and VOC -- emissions are calculated assuming:
Worst-case daily emissions assumes a total COLD start up of : 1 and a total HOT start up of: 1
Worst-case daily emissions assumes a total shut down of : 1
Remainder of time is spent at maximum normal operation emissions
See above calculation for worst-case daily SO_2 and PM: calculated as 24 hrs of normal operational max emissions rate

CTG/HRSG Stack - Co Firing	Emissions Summary
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CTG Operating Parameters

Ambient Temperature	UNITS	Winter Minimum - 20°F				Yearly Average- 65°F				Summer Maximum - 97°F			
CTG Load Level	Percent Load (%)	100%	100%	80%	60%	100%	100%	80%	60%	100%	100%	80%	60%
Evap Cooling Status	off / on	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Duct Burner Status	off / on	On	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off

Average Emission Rates from CTG (lbs/hr/turbine) - Normal Operation

	UNITS	Winter Minimum - 20°F				Yearly Average- 65°F				Summer Maximum - 97°F			
NO_x (@ 4.0 ppm)	lbm/hr	42.0	34.0			39.7	31.7						
CO (@ 5.0 ppm)	lbm/hr	32.0	25.9			30.2	24.1						
VOC (@ 2.0 ppm)	lbm/hr	7.3	5.9			6.9	5.5						
SO_2 (@ 6.7 ppmv, average) (12.65 ppm duct firing)	lbm/hr	6.3	5.2			6.0	4.8						
$PM_{10} = PM_{2.5}$	lbm/hr	19.8	19.8			19.8	19.8						
NH_3 (@ 5.0 ppm slip)	lbm/hr	19.4	15.7			18.3	14.6						

All turbine operating parameters and emissions data provided by FLUOR based on expected operating parameters.
Co-firing emissions are controlled at the same amount as natural gas.

Startup / Shutdown Emissions from Turbine (1CT)

Cold Startup			Hot Startup			Shutdown		
180 (min. in cold startup)	Max 1-hr. (lb/hr)	Total (lb/180min)	60 (min. in hot startup)	Max 1-hr. (lb/hr)	Total (lb/60min)	30 (min. in shutdown)	Max 1-hr. (lb/hr)	Total (lb/30min)
NO_X	90.7	272.0	NOx	167.0	167.0	NOx	62.0	62.0
CO	1,679.7	5,039.0	CO	394.0	394.0	CO	126.0	126.0
VOC	266.7	800.0	VOC	98.0	98.0	VOC	21.0	21.0
SO_2 (@ 12.65 ppmv)	5.1	15.3	SO2	5.1	5.1	SO2	2.6	2.6
$PM_{10} = PM_{2.5}$	19.0	57.0	$PM_{10} = PM_{2.5}$	19.8	19.8	$PM_{10} = PM_{2.5}$	5.0	5.0

All turbine operating parameters and emissions data provided by FLUOR based on expected operating parameters.
CTGs will always be started burning natural gas. Startup and shutdown emission rates above reflect natural gas.
Startup and shutdown SO_2 emissions will always be lower than normal operation max SO_2 emissions. Startup and shutdown emissions are assumed equal to normal operations (burning natural gas) at the max emission rate.

Average Annual Emissions

			Pollutant	Turbine Emissions lb/yr/CT	Emissions ton/yr/CT	Emissions g/sec/CT
Total Hours of Operation	8,322.0					
Total Number of Cold Starts	10.0					
Cold Start Duration (hr)	3.0		NO_X	335,530.2	167.8	4.8
Total Number of Hot Starts	20.0		CO	311,411.4	155.7	4.5
Hot Start Duration (hr)	1.0		VOC	67,565.7	33.8	1.0
Total Number of Shutdowns	30.0		SO_2	49,479.2	24.7	0.7
Shutdown Duration (hr)	0.5		$PM_{10} = PM_{2.5}$	164,604.6	82.3	2.4
Duct Burner Operation (hr)	8,257.0		NH_3	151,341.7	75.7	2.2
Average Normal Operation (hr)	0.0					

Assumptions:
Average annual normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

First Quarter Emissions (Jan, Feb, Mar)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	83,882.6	41.9
Total Number of Hot Starts	5.0	CO	77,852.9	38.9
Hot Start Duration (hr)	1.0	VOC	16,891.4	8.4
Total Number of Shutdowns	7.5	SO_2	12,369.8	6.2
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	41,151.2	20.6
Duct Burner Operation (hr)	2,064.3	NH_3	37,835.4	18.9
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Second Quarter Emissions (Apr, May, Jun)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	83,882.6	41.9
Total Number of Hot Starts	5.0	CO	77,852.9	38.9
Hot Start Duration (hr)	1.0	VOC	16,891.4	8.4
Total Number of Shutdowns	7.5	SO_2	12,369.8	6.2
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	41,151.2	20.6
Duct Burner Operation (hr)	2,064.3	NH_3	37,835.4	18.9
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Modeling Worst-Case 1 hr Emissions per Turbine

Pollutant	lb/hr/CT	g/sec/CT
NOx	167.0	21.0
CO	1,679.7	211.6
SO_2	6.3	0.80

Assumptions:
Startup emissions represent worst case hr for NOx and CO. Startup and shutdown only burn natural gas.
NOx emissions are from hot start
CO emissions are from cold start
Normal operation co firing represents worst case SO_2.
Calculation assumes that startup and shutdown SO_2 emissions will always be lower than normal operational (burning natural gas) max SO_2 emissions.

Third Quarter Emissions (Jul, Aug, Sep)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	83,882.6	41.9
Total Number of Hot Starts	5.0	CO	77,852.9	38.9
Hot Start Duration (hr)	1.0	VOC	16,891.4	8.4
Total Number of Shutdowns	7.5	SO_2	12,369.8	6.2
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	41,151.2	20.6
Duct Burner Operation (hr)	2,064.3	NH_3	37,835.4	18.9
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

Fourth Quarter Emissions (Oct, Nov, Dec)

		Pollutant	Turbine Emissions lb/qtr/CT	Emissions ton/qtr/CT
Total Hours of Operation	2,080.5			
Total Number of Cold Starts	2.5			
Cold Start Duration (hr)	3.0	NO_X	83,882.6	41.9
Total Number of Hot Starts	5.0	CO	77,852.9	38.9
Hot Start Duration (hr)	1.0	VOC	16,891.4	8.4
Total Number of Shutdowns	7.5	SO_2	12,369.8	6.2
Shutdown Duration (hr)	0.5	$PM_{10} = PM_{2.5}$	41,151.2	20.6
Duct Burner Operation (hr)	2,064.3	NH_3	37,835.4	18.9
Average Normal Operation (hr)	0.0			

Assumptions:
Quarterly normal operational emissions are calculated using yearly average- 65°F, at 100 % load.
Quarterly duct burner emissions are calculated using yearly average- 65°F, at 100 % load with duct burners.

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Modeling Worst-Case 3 hr Emissions per Turbine

	hr	emission rate lb/hr	Emissions lb/CT	
Total Hours of Operation	3.0			
Startup Duration	0.0		0.0	contribution over 3 hr from start up
Shutdown Duration	0.0		0.0	contribution over 3 hr from shut down
Hours of Normal Operation (co firing)	3.0	6.3	18.9	contribution over 3 hr from normal operation
SO_2 worst-case 3 hr emissions per turbine	18.9	lb/3 hr		
SO_2 worst-case 1 hr emissions per turbine	6.3	lb/hr		
SO_2 modeling worst-case emissions per turbine	0.8	g/sec		

Assumptions:
Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
Normal operation co firing represents worst case SO_2.
Worst-case 3 hr emissions assumes a total start up of : 0
Worst-case 3 hr emissions assumes a total shut down of : 0
Calculation assumes that startup and shutdown SO_2 emissions will always be lower than normal operational (burning natural gas) SO_2 emissions.

Modeling Worst-Case 8 hr Emissions per Turbine

	hr	emission rate lb/hr	Emissions lb/CT	
Total Hours of Operation	8.0			
Startup Duration (1 cold start and 1 hot start)	4.0		5,433.0	contribution over 8 hr from start up
Shutdown Duration	0.5		126.0	contribution over 8 hr from shut down
Hours of Normal Operation (co firing)	3.5	32.0	112.0	contribution over 8 hr from normal operation
CO worst-case 8 hr emissions per turbine	5,671.0	lb/8 hr		
CO worst-case 1 hr emissions per turbine	708.9	lb/hr		
CO modeling worst-case emissions per turbine	89.3	g/sec		

Assumptions:
Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Normal operation assumes max rate.
Worst-case 8 hr emissions assumes a total COLD start up of : 1
Worst-case 8 hr emissions assumes a total HOT start up of : 1
Worst-case 8 hr emissions assumes a total shut down of : 1

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Worst-Case Daily Emissions per Turbine and Modeling Worst-Case 24 Hour Emission Rate

SO_2 (lb/day/CT)	151.5
SO2 (g/s/CT) (co firing)	0.8
$PM_{10} = PM_{2.5}$ (lb/day/CT)	475.2
$PM_{10} = PM_{2.5}$ (g/s/CT) (cofiring)	2.5

Assumptions:
Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.
For SO_2 24 hrs of normal operation max emission rate
For PM 24 hrs of normal operation max emission rate

Worst-Case Daily Emissions per Turbine and Modeling Worst-Case 24 Hour Emission Rate

Pollutant	Time in Cold Startup hr	Startup Emission Rate lb/start	Time in Hot Startup hr	Startup Emission Rate lb/start	Time in Shut Down hr	Shutdown Emission Rate lb/shutdown	Time in Normal Operation hr	Normal Operation Emission Rate lb/hr	Worst-Case Daily Emissions lb/day/CT	Modeling Worst-Case 24 Hr Emission g/s/CT
NOx	3.0	272.0	1.0	167.0	0.5	62.0	19.5	42.0	1,320.6	6.9
CO	3.0	5,039.0	1.0	394.0	0.5	126.0	19.5	32.0	6,183.0	
VOC	3.0	800.0	1.0	98.0	0.5	21.0	19.5	7.3	1,061.5	
SO_2	3.0	15.3	1.0	5.1	0.5	2.6	19.5	6.3	146.1	0.8
$PM_{10} = PM_{2.5}$	3.0	57.0	1.0	19.8	0.5	5.0	19.5	19.8	467.9	2.5

Assumptions:
For NOx, CO, and VOC -- emissions are calculated assuming:
Worst-case daily emissions assumes a total COLD start up of : 1 and a total HOT start up of: 1
Worst-case daily emissions assumes a total shut down of : 1
Remainder of time is spent at maximum normal operation emissions
See above calculation for worst-case daily SO_2 and PM: calculated as 24 hrs of normal operationat max emissions rate

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Auxiliary Boiler - Annual Operating Emissions

Total Hours of Operation	2,190	hr/yr
Firing Rate	142	MMBtu/hr

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
547.5	547.5	547.5	547.5

Assuming equal operation in each quarter

Auxiliary Boiler Emission Factors

NOx (low NOx burner and flue gas recirculation, 5 ppmvd (3% O2))	0.006	lb/MMBtu
CO (50 ppmvd (3% O2))	0.037	lb/MMBtu
VOC	0.004	lb/MMBtu
SO_2 (12.65 ppmv total sulfur in pipeline natural gas)	0.00204	lb/MMBtu
$PM_{10} = PM_{2.5}$	0.005	lb/MMBtu
NH_3 (@ 5.0 ppm slip)	0.0022	lb/MMBtu

Auxiliary Boiler Pollutant Emission Rates

	Auxiliary Boiler Emissions				
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/qtr**	**ton/yr**
NOx	0.85	20.45	1,865.88	0.23	0.9
CO	5.25	126.10	11,506.26	1.44	5.8
VOC	0.57	13.63	1,243.92	0.16	0.6
SO_2	0.29	6.96	635.09	0.08	0.3
$PM_{10} = PM_{2.5}$	0.71	17.04	1,554.90	0.19	0.8
NH_3 (@ 5.0 ppm slip)	0.31	7.50	684.16	0.09	0.3

Modeling Worst-Case 1 hr Emissions

NOx (g/sec)	0.1
CO (g/sec)	0.7
SO_2 (g/sec)	0.04

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

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Modeling Worst-Case 3 hr Emissions

SO_2 (lb/3-hr)	0.87
SO_2 (g/sec)	0.04

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.

Modeling Worst-Case 8 hr Emissions

CO (lb/8-hr)	42.03
CO (g/sec)	0.7

Only CO is considered for an average 8-hour Ambient Air Quality Standard.

Modeling Worst-Case 24 Hour Emissions

SO_2 (lb/24-hr)	6.96
SO_2 (g/sec)	0.04
$PM_{10} = PM_{2.5}$ (lb/24-hr)	17.04
$PM_{10} = PM_{2.5}$ (g/sec)	0.09

Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.

Modeling Annual Average Emissions

NOx (g/sec)	0.03
CO (g/sec)	0.2
VOC (g/sec)	0.02
SO_2 (g/sec)	0.01
$PM_{10} = PM_{2.5}$ (g/sec)	0.02

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Gasification Flare - Normal Operating Emissions From Pilot

Total Hours of Operation	8,760	hr/yr
Gasification Flare Pilot Fuel Use =	0.5	MMBtu/hr

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
2190	2190	2190	2190

Assuming equal operation in each quarter

Pilot Pollutant Emission Factors

NOx (lb/MMBtu, HHV)	0.12
CO (lb/MMBtu, HHV)	0.08
VOC (lb/MMBtu, HHV)	0.0013
SO_2 (lb/MMBtu, HHV) (12.65 ppm)	0.002
$PM_{10} = PM_{2.5}$ (lb/MMBtu, HHV)	0.003

Pilot Pollutant Emission Rates

	Pilot Emissions				
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/qtr**	**ton/yr**
NOx	0.060	1.44	525.60	0.07	0.26
CO	0.040	0.96	350.40	0.04	0.18
VOC	0.001	0.02	5.69	0.0007	0.003
SO_2	0.0010	0.02	8.94	0.0011	0.004
$PM_{10} = PM_{2.5}$	0.002	0.04	13.14	0.00	0.007

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Gasification Flare - Operating Emissions During Gasifier Startup, Shutdown, and CTG Wash

Total Flare SU/SD/CTG wash Operation	196,900	MMBtu/yr
Wet Unshifted Gas Heat Rate	900	MMBtu/hr
Dry Shifted Gas Heat Rate	770	MMBtu/hr
H2-rich gas during CTG wash	1695	MMBtu/hr

Startup and shutdown flared gas scenario

Cold plant startup =	30,000 MMBtu/yr (1 event)	(assume 20% unshifted)
Plant shutdown =	500 MMBtu/yr (1 event)	(assume 100% unshifted)
Gasifier outages =	60,000 MMBtu/yr (24 events)	(assume 100% unshifted)
Gasifier hot restarts =	25,000 MMBtu/yr (12 events)	(assume 100% unshifted)
Total SU/SD =	**115,500 MMBtu/yr**	(approx 79% unshifted)
Off-line CTG wash* =	81,400 MMBtu/yr (12 events)	(assume 100% shifted)
Total =	**196,900 MMBtu/yr**	(approx 50% unshifted)

SU/SD Flare Pollutant Emission Factors

NOx (lb/MMBtu, HHV)	0.07
CO (lb/MMBtu, HHV) (wet)	2.00
CO (lb/MMBtu, HHV) (dry)	0.37
VOC (lb/MMBtu, HHV)	0
SO_2 (lb/MMBtu, HHV)	0
PM_{10} = $PM_{2.5}$ (lb/MMBtu, HHV)	0

Off-line CTG Wash Flare Pollutant Emission Factors

NOx (lb/MMBtu, HHV)	0.07
CO (lb/MMBtu, HHV)	0.37
VOC (lb/MMBtu, HHV)	0
SO_2 (lb/MMBtu, HHV)	0.0028
PM_{10} = $PM_{2.5}$ (lb/MMBtu, HHV)	0

SU/SD Flare Pollutant Emission Rates

			SU/SD Flare Emissions				
Pollutant	**lb/hr (wet)**	**lb/hr (dry)**	**% Wet**	**% Dry**	**lb/hr (wet/dry)**	**ton/qtr (wet/dry)**	**ton/yr (wet/dry)**
NOx	63.0	53.9	79.2%	20.8%	61.11	1.01	4.04
CO	1800.0	284.9	79.2%	20.8%	1,485.17	23.99	95.94
VOC	0	0	79.2%	20.8%	0	0	0.00
SO_2	0	0	79.2%	20.8%	0	0	0.00
PM_{10} = $PM_{2.5}$	0	0	79.2%	20.8%	0	0	0.00

Total emissions are determined based on the fractional amount of wet and dry gas burned.

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Offline CTG Wash Pollutant Emission Rates

	CTG Wash Flare Emissions		
Pollutant	**lb/hr**	**ton/qtr**	**ton/yr**
NOx	118.65	0.71	2.85
CO	627.15	3.76	15.06
VOC	0.00	0	0.00
SO_2	4.75	0	0.11
$PM_{10} = PM_{2.5}$	0.00	0	0.00

Total emissions are determined based on 48 hr/yr @ 70% gasifier capacity of CTG Wash

Total Gasification Flare Emissions

Pollutant	Emissions Pilot (ton/yr)	SU/SD/Wash (ton/yr)	Total (ton/qtr)	Total (ton/yr)
NOx	0.26	6.89	1.79	7.2
CO	0.18	111.00	27.79	111.2
VOC	0.003	0.00	0.001	0.003
SO_2	0.004	0.11	0.030	0.118
$PM_{10} = PM_{2.5}$	0.01	0.00	0.002	0.01

Modeling Worst-Case 1 hr Emissions

NOx (g/sec)	14.9
CO (g/sec)	226.8
SO_2 (g/sec)	0.5980

Only NOx, CO, and SO_2 are considered for an average 1-hour Ambient Air Quality Standard.
CO rate is taken from the SU/SD flaring events
NOx and SO_2 rate are taken from CTG wash operation

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

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Modeling Worst-Case 3 hr Emissions

SO_2 (lb/3-hr)	14.238
SO_2 (g/sec)	0.5980

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
SO_2 pounds per 3-hr assumes three (3) hours of CTG wash operation.

Modeling Worst-Case 8 hr Emissions

CO (lb/8-hr)	14,400.00
CO (g/sec)	226.8

Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Pounds per 8-hr assumes eight (8) hours of SU/SD flaring events.

Modeling Worst-Case 24 Hour Emissions

SO_2 (lb/24-hr)	113.90
SO_2 (g/sec)	0.5980
$PM_{10} = PM_{2.5}$ (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.
PM_{10} pounds per 24-hr assumes 24 hours of pilot operation.
SO_2 pounds per 24-hr assumes 24 hours of CTG wash operation.

Modeling Annual Average Emissions

NOx (g/sec)	0.2
CO (g/sec)	3.2
VOC (g/sec)	0.0001
SO_2 (g/sec)	0.0034
$PM_{10} = PM_{2.5}$ (g/sec)	0.0002

Pounds per year assumes contributions from both pilot operation and SU/SD/CTG Wash flaring

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SRU Flare - Normal Operating Emissions from Pilot

Total Hours of Operation	8,760	hr/yr
SRU Flare Pilot Firing Rate	0.3	MMBtu/hr

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
2190	2190	2190	2190

Assuming equal operation in each quarter

Pilot Pollutant Emission Factors

NOx (lb/MMBtu, HHV)	0.12
CO (lb/MMBtu, HHV)	0.08
VOC (lb/MMBtu, HHV)	0.0013
SO_2 (lb/MMBtu, HHV) (12.65 ppm)	0.002
$PM_{10} = PM_{2.5}$ (lb/MMBtu, HHV)	0.003

Pilot Pollutant Emission Rates

	Pilot Emissions				
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/qtr**	**ton/yr**
NOx	0.036	0.86	315.36	0.04	0.2
CO	0.024	0.58	210.24	0.03	0.1
VOC	0.0004	0.01	3.42	0.0004	0.002
SO_2	0.0006	0.01	5.37	0.0007	0.003
$PM_{10} = PM_{2.5}$	0.0009	0.02	7.88	0.00	0.004

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SRU - Operating Emissions During Gasifier Startup and Shutdown

Natural Gas Heat Rate (assist gas)	36.0	MMBtu/hr
Approximate Operating Hours	40.0	hr/yr

Assumed: 12 hours/ event, with maximum of 1 event /day

Control efficiency of scrubber = 99.60%
Acid gas lb/hr SO2 = 4,600 lb/hr scrubbed SO2= 18.4

SU/SD Flare Pollutant Emission Factors

NOx (lb/hr)	4.32
CO (lb/hr)	2.88
VOC (lb/hr)	0.05
SO_2 (lb/hr) from natural gas	0.07
SO_2 (lb/hr) from sour flaring	18.40
PM_{10} = $PM_{2.5}$(lb/hr)	0.11

Natural gas emissions are the same as those listed for the pilot multiplied by the heat rate of the assist gas

SU/SD Flare Pollutant Emission Rates

	SU/SD Flare Emissions				
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/qtr**	**ton/yr**
NOx	4.32	51.8	172.8	0.02160	0.0864
CO	2.88	34.6	115.2	0.01440	0.0576
VOC	0.05	0.6	1.9	0	0.0009
SO_2	18.47	221.7	738.9	0.09	0.3695
PM_{10} = $PM_{2.5}$	0.11	1.3	4.3	0	0.0022

SRU Flare - Total Annual Emissions

	Emissions			
Pollutant	**Pilot (ton/yr)**	**SU/SD (ton/yr)**	**Total (ton/qtr)**	**Total (ton/yr)**
NOx	0.16	0.0864	0.06	0.2
CO	0.11	0.0576	0.04	0.2
VOC	0.002	0.0009	0.001	0.003
SO_2	0.003	0.37	0.093	0.4
PM_{10} = $PM_{2.5}$	0.004	0.0022	0.002	0.006

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Modeling Worst-Case 1 hr Emissions

NOx (g/sec)	0.544
CO (g/sec)	0.363
SO_2 (g/sec)	2.33

Only NOx, CO, and SO2 are considered for an average 1-hour Ambient Air Quality Standard.
NOx, CO, and SO2 one (1) hr rates are from taken from the SU/SD flaring events

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)	55.42
SO_2 (g/sec)	2.33

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
Pounds per 3-hr assumes aproximately 3 hours of SU/SD flaring.

Modeling Worst-Case 8 hr Emissions

CO (lb/8-hr)	147.79
CO (g/sec)	2.33

Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Pounds per 8-hr assumes aproximately 8 hours of SU/SD flaring.

Modeling Worst-Case 24 Hour Emissions

SO_2 (lb/24-hr)	221.69
SO_2 (g/sec)	1.16
$PM_{10} = PM_{2.5}$ (lb/24-hr)	1.31
$PM_{10} = PM_{2.5}$ (g/sec)	0.0069

Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.
SO_2 and PM pounds per 24-hr assume aproximately 12 hours of SU/SD flaring and the remainder in pilot operation.

Modeling Annual Average Emissions

NOx (g/sec)	0.007
CO (g/sec)	0.005
VOC (g/sec)	0.00008
SO_2 (g/sec)	0.011
$PM_{10} = PM_{2.5}$ (g/sec)	0.0002

Pounds per year assumes contributions from both pilot operation and SU/SD flaring

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Rectisol - Normal Operating Emissions from Pilot

Total Hours of Operation	8,760	hr/yr
Rectisol Flare Pilot Firing Rate	0.3	MMBtu/hr

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
2190	2190	2190	2190

Assuming equal operation in each quarter

Pilot Pollutant Emission Factors

NOx (lb/MMBtu, HHV)	0.12
CO (lb/MMBtu, HHV)	0.08
VOC (lb/MMBtu, HHV)	0.0013
SO_2 (lb/MMBtu, HHV) (12.65 ppm)	0.002
$PM_{10} = PM_{2.5}$ (lb/MMBtu, HHV)	0.003

Pilot Pollutant Emission Rates

Pollutant	Pilot Emissions lb/hr	lb/day	lb/yr	ton/qtr	ton/yr
NOx	0.036	0.86	315.36	0.04	0.2
CO	0.024	0.58	210.24	0.03	0.1
VOC	0.0004	0.01	3.42	0.0004	0.002
SO_2	0.0006	0.01	5.37	0.0007	0.003
$PM_{10} = PM_{2.5}$	0.0009	0.02	7.88	0.00	0.004

Please note that there are no planned flaring is expected with this flare.

Rectisol Flare - Total Annual Emissions

Pollutant	Emissions Pilot (ton/yr)	Total (ton/qtr)	Total (ton/yr)
NOx	0.16	0.04	0.2
CO	0.11	0.03	0.1
VOC	0.002	0.000	0.002
SO_2	0.003	0.001	0.003
$PM_{10} = PM_{2.5}$	0.004	0.001	0.004

Modeling Worst-Case 1 hr Emissions

NOx (g/sec)	0.005
CO (g/sec)	0.003
SO_2 (g/sec)	0.0001

Only NOx, CO, and SO2 are considered for an average 1-hour Ambient Air Quality Standard.
NOx, CO, and SO2 one (1) hr rates are from taken from the natural gas pilot emissions

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

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Modeling Worst-Case 3 hr Emissions

SO_2 (lb/3-hr)	0.0018
SO_2 (g/sec)	0.0001

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
Pounds per 3-hr assumes aproximately 3 hours the natural gas pilot emissions.

Modeling Worst-Case 8 hr Emissions

CO (lb/8-hr)	0.19
CO (g/sec)	0.003

Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Pounds per 8-hr assumes aproximately 8 hours of pilot 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)	0.02
$PM_{10} = PM_{2.5}$ (g/sec)	0.0001

Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.
SO_2 and PM pounds per 24-hr assume aproximately 24 hours of pilot operation.

Modeling Annual Average Emissions

NOx (g/sec)	0.005
CO (g/sec)	0.003
VOC (g/sec)	0.00005
SO_2 (g/sec)	0.0001
$PM_{10} = PM_{2.5}$ (g/sec)	0.0001

Pounds per year assumes contributions from both pilot operation and SU/SD flaring

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Thermal Oxidizer - Process Vent Disposal Emissions

Total Hours of Operation	8,460	hr/yr
Thermal Oxidizer Firing Rate	10	MMBtu/hr

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
2115	2115	2115	2115

Assuming equal operation in each quarter

Process Vent Gas Pollutant Emission Factors

NOx (lb/MMBtu, HHV)	0.24
CO (lb/MMBtu, HHV)	0.20
VOC (lb/MMBtu, HHV)	0.0060
SO_2 (lb/MMBtu, HHV)	See Below
$PM_{10} = PM_{2.5}$ (lb/MMBtu, HHV)	0.008

Assume an allowance of 2 lb/hr SO_2 emission to account for sulfur in the various vent streams plus fuel.

Process Vent Gas Pollutant Emission Rates

	Process Vent Gas Emissions				
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/qtr**	**ton/yr**
NOx	2.40	57.60	20,304.00	2.54	10.2
CO	2.00	48.00	16,920.00	2.12	8.5
VOC	0.06	1.44	507.60	0.0635	0.3
SO_2	2.00	48.00	16,920.00	2.1150	8.5
$PM_{10} = PM_{2.5}$	0.08	1.92	676.80	0.08	0.3

Assume an allowance of 2 lb/hr SO_2 emission to account for sulfur in the various vent streams plus fuel.

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Thermal Oxidizer - SRU Startup Waste Gas Disposal

Total Hours of Operation	300	hr/yr
Thermal Oxidizer Firing Rate	10	MMBtu/hr

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
75	75	75	75

Assuming equal operation in each quarter

SRU Startup Waste Gas Disposal Emission Factors

NOx (lb/MMBtu, HHV)	0.24
CO (lb/MMBtu, HHV)	0.20
VOC (lb/MMBtu, HHV)	0.006
SO_2 (lb/MMBtu, HHV) (12.65 ppm)	0.002
$PM_{10} = PM_{2.5}$ (lb/MMBtu, HHV)	0.008

SRU Startup Waste Gas Disposal Pollutant Emission Rates

	SRU Startup Waste Gas Disposal Emissions				
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/qtr**	**ton/yr**
NOx	2.40	57.60	720.00	0.09	0.36
CO	2.00	48.00	600.00	0.08	0.30
VOC	0.06	1.44	18.00	0.002	0.009
SO_2	0.02	0.49	6.17	0.001	0.003
$PM_{10} = PM_{2.5}$	0.08	1.92	24.00	0.003	0.012

Thermal Oxidizer - Total Annual Emissions

	Emissions		
Pollutant	**Vent and SU/SD (ton/yr)**	**Total (ton/qtr)**	**Total (ton/yr)**
NOx	10.51	2.63	10.5
CO	8.76	2.19	8.8
VOC	0.26	0.07	0.3
SO_2	8.46	2.12	8.5
$PM_{10} = PM_{2.5}$	0.35	0.09	0.4

Please note that the annual emissions were calculated based on the total emission from process vent and SU/SD.

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Modeling Worst-Case 1 hr Emissions

NOx (g/sec)	0.3
CO (g/sec)	0.25
SO_2 (g/sec)	0.25

Only NOx, CO, and SO_2 are considered for an average 1-hour Ambient Air Quality Standard.
NOx, CO, and SO_2 one (1) hr rates include contributions from process venting.

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)	6.00
SO_2 (g/sec)	0.3

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
SO_2 pounds per 3-hr assumes three (3) hours of oxidation from process venting.

Modeling Worst-Case 8 hr Emissions

CO (lb/8-hr)	16.00
CO (g/sec)	0.3

Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Pounds per 8-hr assumes eight (8) hours of oxidation from process venting.

Modeling Worst-Case 24 Hour Emissions

SO_2 (lb/24-hr)	48.00
SO_2 (g/sec)	0.3
$PM_{10} = PM_{2.5}$ (lb/24-hr)	1.92
$PM_{10} = PM_{2.5}$ (g/sec)	0.01

Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.
Pounds per 24-hr assumes 24 hours of oxidation from process venting.

Modeling Annual Average Emissions

NOx (g/sec)	0.3
CO (g/sec)	0.25
VOC (g/sec)	0.01
SO_2 (g/sec)	0.2
$PM_{10} = PM_{2.5}$ (g/sec)	0.01

Pounds per year assumes all contributions from annual waste gas oxidation and periodic SRU startup.

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Gasifier Warming Emissions - Normal Operation

Total Hours of Operation (3 heaters)	3,600	hr/yr
Gasifier Firing Rate	18	MMBtu/hr

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
900	900	900	900

Assuming equal operation in each quarter

Gasifier Pollutant Emission Factors

NOx (lb/MMBtu, HHV)	0.24
CO (lb/MMBtu, HHV)	0.35
VOC (lb/MMBtu, HHV)	0.070
SO_2 (lb/MMBtu, HHV) (12.65 ppm)	0.002
$PM_{10} = PM_{2.5}$ (lb/MMBtu, HHV)	0.008

Gasifier Pollutant Emission Rates (3 Gasifier Heaters operation scenario)

	Gasifier Emissions				
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/qtr**	**ton/yr**
NOx	8.64	207.36	15,552.00	1.94	7.8
CO	12.60	302.40	22,680.00	2.84	11.3
VOC	2.52	60.48	4,536.00	0.57	2.3
SO_2	0.07	1.76	132.19	0.02	0.1
$PM_{10} = PM_{2.5}$	0.29	6.91	518.40	0.06	0.3

Please note that there are three gassifiers; However, under normal operations,up to two heaters operate at a time.

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Modeling Worst-Case 1 hr Emissions per Gasifier Heater

NOx (g/sec)	0.5
CO (g/sec)	0.8
SO_2 (g/sec)	0.0046

Only NOx, CO, and SO_2 are considered for an average 1-hour Ambient Air Quality Standard.
NOx, CO, and SO_2 one (1) hr rates assume normal operation.

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

Modeling Worst-Case 3 hr Emissions per Gasifier Heater

SO_2 (lb/3-hr)	0.11
SO_2 (g/sec)	0.0046

Only SO_2 is considered for an average 3-hour Ambient Air Quality Standard.
SO_2 pounds per 3-hr assumes three (3) hours of normal operation.

Modeling Worst-Case 8 hr Emissions per Gasifier Heater

CO (lb/8-hr)	50.40
CO (g/sec)	0.8

Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Pounds per 8-hr assumes eight (8) hours of normal operation.

Modeling Worst-Case 24 Hour Emissions per Gasifier Heater

SO_2 (lb/24-hr)	0.88
SO_2 (g/sec)	0.0046
$PM_{10} = PM_{2.5}$ (lb/24-hr)	3.46
$PM_{10} = PM_{2.5}$ (g/sec)	0.02

Only SO_2 and PM are considered for an average 24-hour Ambient Air Quality Standard.
Pounds per 24-hr assumes 24 hours of normal operation.

Modeling Annual Average Emissions per Gasifier Heater

NOx (g/sec)	0.07
CO (g/sec)	0.1087
VOC (g/sec)	0.0217
SO_2 (g/sec)	0.0006
$PM_{10} = PM_{2.5}$ (g/sec)	0.0025

Pounds per year assumes 3,600 hours of annual normal operation (3 heaters with 1,200 hr/yr of operation for each gasifier heater)

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Cooling Towers - Annual Operating Emissions

Total Hours of Operation	8,322	hr/yr

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
2080.5	2080.5	2080.5	2080.5

Assuming equal operation in each quarter

Cooling Tower Operating Parameters

	Power Block	Gasification	ASU	Basis
Cooling water (CW) circulation rate, gpm	175,000	42,300	40,200	Typical plant performance
CW circulation rate (million lb/hr)	88	21	20	
CW dissolved solids (ppmw)	9,000	9,000	9,000	(See note)
Drift, fraction of circulating CW	0.0005%	0.0005%	0.0005%	Expected BACT

Note: Assumed 9,000 ppm TDS in circulating cooling water. Circulating water could range from 1200 to 90,000 ppm TDS depending on makeup water quality and tower operation. PM10 emissions would vary proportionately.

Cooling Tower PM_{10} Emissions

	Cooling Tower PM_{10} Emissions				
	lb/hr	**lb/day**	**lb/yr**	**ton/qtr**	**ton/yr**
Power Block Cooling Tower PM_{10} Emissions	3.94	94.50	32,767.88	4.10	16.38
Gasification Cooling Tower PM_{10} Emissions	0.95	22.84	7,920.46	0.99	3.96
ASU Cooling Tower PM_{10} Emissions	0.90	21.71	7,527.25	0.94	3.76

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Total Cooling Tower PM_{10} Emissions

	(ton/yr)
PM_{10}	24.11
$PM_{2.5}$	14.46

$PM_{2.5}$ emission factors were determined by multiplying PM_{10} numbers by a "$PM_{2.5}$ fraction of PM_{10}" value. Fractional values for $PM_{2.5}$ were taken from the SCAQMD guidance: Final - Methodology to Calculate $PM_{2.5}$ and $PM_{2.5}$ Significance Thresholds, October 2006: Appendix A - Updated CEIDARS Table with $PM_{2.5}$ Fractions.

Modeling Worst-Case 24 Hour Emissions	Power Block	Gasification	ASU
Cells per Cooling Tower	13	4	4
PM_{10} (lb/24-hr)	94.50	22.84	21.71
PM_{10} (g/sec/cell)	0.038	0.030	0.028
$PM_{2.5}$ (lb/24-hr)	56.70	13.71	13.02
$PM_{2.5}$ (g/sec/cell)	0.023	0.018	0.017

PM is considered for an average 24-hour Ambient Air Quality Standard.
Pounds per 24-hr assumes 24 hours of continual operation.

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

Modeling Worst-Case Annual Emissions	Power Block	Gasification	ASU
Cells per Cooling Tower	13	4	4
PM_{10} (ton/yr)	16.38	3.96	3.76
PM_{10} (g/sec/cell)	0.036	0.028	0.027
$PM_{2.5}$ (lb/24-hr)	9.830	2.376	2.258
$PM_{2.5}$ (g/sec/cell)	0.022	0.017	0.016

PM is considered for an annual average Ambient Air Quality Standard.
Assumes continual annual operation.

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Emergency Generator - Expected Emergency Operation and Maintenance

Total Hours of Operation	52	hr/yr
Generator Specification	2,922	Bhp

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
13	13	13	13

Assuming equal operation in each quarter

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/qtr**	**ton/yr**
NOx	3.22	6.44	167.49	0.02	0.08
CO	16.75	33.50	870.93	0.11	0.44
VOC	1.93	3.87	100.49	0.01	0.05
SO_2	0.03	0.06	1.46	0.00	0.00
$PM_{10} = PM_{2.5}$	0.45	0.90	23.45	0.00	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 two (2) hours of operation for maintenance and testing.

Please note that there are two generators; all emissions are shown for individual generators.

Modeling Worst-Case 1 hr Emissions (per generator)

NOx (g/sec)	0.4
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

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Modeling Worst-Case 3 hr Emissions (per generator)

SO_2 (lb/3-hr)	0.06
SO_2 (g/sec)	0.002

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)	33.50
CO (g/sec)	0.53

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)	0.06
SO_2 (g/sec)	0.0003
$PM_{10} = PM_{2.5}$ (lb/24-hr)	0.90
$PM_{10} = PM_{2.5}$ (g/sec)	0.005

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)

NOx (g/sec)	0.002
CO (g/sec)	0.013
VOC (g/sec)	0.001
SO_2 (g/sec)	0.00002
$PM_{10} = PM_{2.5}$ (g/sec)	0.0003

Pounds per year assumes 52 hours of operation.

Emergency Diesel Firewater Pump — Emissions Summary

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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

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
25	25	25	25

Assuming equal operation in each quarter

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/qtr**	**ton/yr**
NOx	1.84	3.68	183.86	0.02	0.1
CO	3.19	6.37	318.69	0.04	0.2
VOC	0.17	0.34	17.16	0.00	0.01
SO_2	0.01	0.01	0.56	0.0001	0.0003
$PM_{10} = PM_{2.5}$	0.02	0.04	1.84	0.00	0.00

Fuel sulfur content =	15	ppmw
SO_2 emissions =	0.20	lb SO_2/1000 gal
Fuel flow	28.00	gal/hr

Pounds per day assumes two (2) hours of operation for maintenance and testing.

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Modeling Worst-Case 1 hr Emissions

NOx (g/sec)	0.2
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

NOx (g/sec)	0.003
CO (g/sec)	0.005
VOC (g/sec)	0.0002
SO_2 (g/sec)	0.00001
$PM_{10} = PM_{2.5}$ (g/sec)	0.00003

Pounds per year assumes 100 hours of operation.

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Intermittent CO_2 Vent - Venting Operation

Total Days of Operation	21	day/yr
Total Hours of Operation	504	hr/yr
Total Flow	656,000	lb/hr
Total Flow	15,150	lbmol/hr

Hours per Qtr			
Q1	**Q2**	**Q3**	**Q4**
126	126	126	126

Assuming equal operation in each quarter

Vent Gas Pollutant Emission Factors

CO (ppmv)	1000
VOC (ppmv)	40
H_2S (ppmv)	10

Molecular weight

H_2S	34	lb/lbmol
CO	28	lb/lbmol
VOC	16	lb/lbmol

(Molecular weight of VOC is based on CH4)

Vent Gas Pollutant Emission Rates

	Vent Gas Emissions				
Pollutant	**lb/hr**	**lb/day**	**lb/yr**	**ton/qtr**	**ton/yr**
CO	424.20	10,180.88	213,798.43	26.72	106.9
VOC	9.70	232.71	4,886.82	0.61	2.4
H_2S	5.15	123.62	2,596.12	0.32	1.3

Note that no SO2 is emitted since no oxidation occurs in the CO2 vent

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Modeling Worst-Case 1 hr Emissions

CO (g/sec)	53.4
H_2S (g/sec)	0.6

Only H_2S and CO are considered for an average 1-hour Ambient Air Quality Standard.
H_2S and CO one (1) hr rates assume normal venting operation.

Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

Modeling Worst-Case 8 hr Emissions

CO (lb/8-hr)	3,393.63
CO (g/sec)	53.4

Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Pounds per 8-hr assumes eight (8) continuous hours of venting.

Modeling Annual Average Emissions

CO	3.1
VOC	0.1
H2S	0.0

Pounds per year assumes normal venting averaged over the entire year.

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Operation

Total Hours of Operation	8,760	hr/yr

Hours per Qtr			
Q1	Q2	Q3	Q4
2190	2190	2190	2190

Assuming equal operation in each quarter

Description	Dust Collector No.	Max Feed Handling Rate (ton/hr)	Air Flow to Collector (acfm)	Max Collector PM Emission Rate (lb/hr)	Emission Factor (lb/ton)	Max 24-hr Average Feed Rate (ton/hr)	Max 24-hr Average PM Emission (lb/hr)	Annual Average Feed Rate (ton/hr)	Annual Average PM Emission (lb/hr)
Truck Unloading	DC-1	900	6,467	0.277	0.00031	775	0.239	150	0.046
Coke/coal Silos (filling)	DC-2	900	16,376	0.702	0.00078	775	0.604	150	0.117
Mass Flow Bins (in/out)	DC-3	170	7,620	0.327	0.00192	170	0.327	150	0.288
Coke/coal Silos (loadout)	DC-4	170	4,872	0.209	0.00123	170	0.209	150	0.184
Crusher Inlet/Outlet	DC-5	170	4,673	0.200	0.00118	170	0.200	150	0.177
Fluxant Bins (filling)	DC-6	100	1,234	0.053	0.00053	40	0.021	6	0.003

Maximum dust collector PM emission rate based on expected supplier guarantee of 0.005 grain/scf outlet dust loading.

The maximum 24-hr feed rate to the gasifiers is limited by the grinding mill capacity.

Duct Collector Emission Rates

Pollutant	Collector Emissions lb/hr	lb/day	lb/yr	ton/qtr	ton/yr
Dust Collecter 1 (DC-1)	0.24	5.73	404.65	0.05	0.2
Dust Collecter 2 (DC-2)	0.60	14.50	1,024.67	0.13	0.5
Dust Collecter 3 (DC-3)	0.33	7.84	2,524.21	0.32	1.3
Dust Collecter 4 (DC-4)	0.21	5.01	1,613.90	0.20	0.8
Dust Collecter 5 (DC-5)	0.20	4.81	1,547.98	0.19	0.8
Dust Collecter 6 (DC-6)	0.02	0.51	27.80	0.00	0.0

Pounds per hour and pounds per day calculated based on the maximum 24-hr average emission rate.

Pounds per year calculated based on the annual average emission rate.

	lb/yr	ton/qtr	ton/yr
PM_{10}	**7,143.2**	**0.9**	**3.6**
$PM_{2.5}$	**2085.8**	**0.3**	**1.0**

$PM_{2.5}$ emission factors were determined by multiplying PM_{10} numbers by a "$PM_{2.5}$ fraction of PM_{10}" value. Fractional values for $PM_{2.5}$ were taken from the SCAQMD guidance: Final - Methodology to Calculate $PM_{2.5}$ and $PM_{2.5}$ Significance Thresholds, October 2006: Appendix A - Updated CEIDARS Table with $PM_{2.5}$ Fractions. The fractional $PM_{2.5}$ is based on loading and unloading of bulk material

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Parameters

Days per year:	365
Hours per day:	24
Minutes per hour:	60
Seconds per minute:	60

Modeling Worst-Case 24 Hour Emissions	DC-1	DC-2	DC-3	DC-4	DC-5	DC-6
PM_{10} (lb/day)	5.73	14.50	7.84	5.01	4.81	0.51
PM_{10} (g/sec)	0.030	0.076	0.041	0.026	0.025	0.003
$PM_{2.5}$ (lb/24-hr)	1.673	4.235	2.289	1.463	1.404	0.148
$PM_{2.5}$ (g/sec)	0.009	0.022	0.012	0.008	0.007	0.001

PM is considered for an average 24-hour Ambient Air Quality Standard.
Pounds per hour calculated based on the maximum 24-hr average emission rate.

Modeling Annual Average Emissions	DC-1	DC-2	DC-3	DC-4	DC-5	DC-6
PM_{10} (lb/yr)	404.65	1,024.67	2,524.21	1,613.90	1,547.98	27.80
PM_{10} (g/sec)	0.006	0.015	0.036	0.023	0.022	0.000
$PM_{2.5}$ (lb/24-hr)	118.158	299.204	737.068	471.259	452.010	8.117
$PM_{2.5}$ (g/sec)	0.002	0.004	0.011	0.007	0.007	0.000

Pounds per year calculated based on the annual average emission rate.

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Summary: Total Controlled Emissions

Compound	Emissions (lb/hr)	Emissions (tpy)
CO_2	9.07	39.72
CO	1.36	5.95
CH_4	5.17E-03	2.26E-02
H_2S	0.55	2.42
COS*	6.94E-05	0.00
CH_3OH*	1.62	7.09
C_3H_6*	1.44	6.33
NH_3	0.04	0.17
HCN*	0.00E+00	0.00E+00
MDEA*	1.42	6.24
Total VOC*	**4.49**	**19.65**

* Per District policy (SSP-2015), VOC emissions are not assessed to components handling fluid streams with a VOC content of 10% of less by weight.

Summary by Volume Source - Emissions are divided by number of Volume Sources

"POWER" Two Volume Sources (Area # 10)

	lb/hr	lb/yr
CO (g/s)	6.43E-05	
H_2S	0.01	73.44
CH_3OH		
C_3H_6		
NH_3	0.01	90.35
HCN	6.54E-05	0.57

"SRU" Three Volume Sources (Area # 9, #11)

	lb/hr	lb/yr
CO (g/s)	8.36E-06	
H_2S	0.04	352.80
CH_3OH	3.48E-05	0.30
C_3H_6		
NH_3		
HCN		

"SWS" Three Volume Sources (Area #6)

	lb/hr	lb/yr
CO (g/s)	3.69E-06	
H_2S	3.80E-03	33.30
CH_3OH		
C_3H_6		
NH_3	0.02	137.12
HCN		

"TGTU" Three Volume Sources (Areas #1, #7, #8, #12, #13)

	lb/hr	lb/yr
CO (g/s)	2.90E-04	
H_2S	0.02	191.83
CH_3OH	0.54	4,723.96
C_3H_6		
NH_3		
HCN		

"AGR" Three Volume Sources (Area # 5)

	lb/hr	lb/yr
CO (g/s)		
H_2S		
CH_3OH		
C_3H_6	0.48	4,219.33
NH_3		
HCN		

"GASIFICATION" Five Volume Sources (Areas #2, #3)

	lb/hr	lb/yr
CO (g/s)	0.03	
H_2S	0.04	390.79
CH_3OH		
C_3H_6		
NH_3	4.13E-04	3.62
HCN	2.05E-04	1.79

"SHIFT" Two Volume Sources (Area # 4)

	lb/hr	lb/yr
CO (g/s)	0.005279	
H_2S	0.06	506.85
CH_3OH		
C_3H_6		
NH_3		
HCN		

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

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.
(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)

Area #1: Methanol

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	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	tpy
Valves	Gas	108	8760	0.68	3.00
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	0.72	3.16
			Total	**1.41**	**6.16**
			CO_2	0.47	2.08
			CO	0.87	3.83
			CH_4	1.09E-03	4.79E-03
			H_2S	0.05	0.22
			COS	4.11E-03	0.02
			NH_3	1.81E-03	0.01
			HCN	9.76E-05	4.28E-04

Area #3: Flash Gas - Gasification

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy
Valves	Gas	49	8760	0.57	2.50
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	0.44	1.95
Connectors	All	151	8760	0.54	2.36
			Total	**1.55**	**6.80**
			CO_2	0.98	4.30
			CO	0.39	1.72
			CH_4	5.50E-04	2.41E-03
			H_2S	0.17	0.76
			COS	4.12E-03	0.02
			NH_3	2.59E-04	1.14E-03
			HCN	9.26E-04	4.06E-03

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	2.45	10.73
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	0.47	2.07
Connectors	All	632	8760	2.40	10.50
			Total	**5.32**	**23.30**
			CO_2	5.12	22.41
			CO	0.08	0.37
			CH_4	3.48E-03	0.02
			H_2S	0.12	0.51
			COS	3.25E-04	1.43E-03

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

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
			CO	3.47E-03	0.02	3.21E-04	1.41E-03
			CH_4	2.94E-04	1.29E-03	2.72E-05	1.19E-04
			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
			CO	1.37E-03	0.01	1.12E-04	4.90E-04
			CH_4	1.17E-04	5.11E-04	9.55E-06	4.18E-05
			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
			CO	2.65E-03	0.01	1.99E-04	8.72E-04
			CH_4	7.19E-05	3.15E-04	5.40E-06	2.37E-05
			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
			CO	0.01	0.06	1.02E-03	4.47E-03
			CH_4	7.67E-05	3.36E-04	5.79E-06	2.54E-05
			H_2S	0.22	0.97	0.02	0.07
			COS	8.03E-04	3.52E-03	6.07E-05	2.66E-04
			NH_3	0.27	1.20	0.02	0.09
			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	68	8760	1.02E-05	4.48E-05
Pump Seals	Light Liquid	0	8760	-	-
Pump Seals	Heavy Liquid	4	8760	2.25E-05	9.87E-05
Compressor Seals	Gas	0	8760	-	-
Connectors	All	297	8760	3.55E-04	1.56E-03
			Total	**3.88E-04**	**1.70E-03**
			H_2S	3.88E-04	1.70E-03

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	72	8760	0.63	2.77
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	290	8760	0.78	3.43
			Total	**1.42**	**6.20**
			CO_2	1.37	6.00
			CO	0.01	0.03
			H_2S	0.04	0.17
			COS	7.28E-04	3.19E-03

Area #13: TGTU Amine

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	264	8760	0.06	0.27
Pump Seals	Light Liquid	0	8760	-	-
Pump Seals	Heavy Liquid	5	8760	0.04	0.19
Compressor Seals	Gas	0	8760	-	-
Connectors	All	746	8760	1.39	6.10
			Total	**1.50**	**6.56**
			CO_2	0.06	0.28
			H_2S	0.01	0.04
			MDEA	1.42	6.24

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.

Area Speciation

Comound	Wt % (WF_{TOC})												
	Methanol	Syn Gas	Flash Gas - Gasification	Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	TGTU Process Gas	TGTU Amine
CO_2	0.00%			90.43%	0.00%	2.50%	44.68%	35.81%	60.32%	68.32%	0.00%	64.65%	1.98%
CO	0.00%			1.48%	0.00%	0.001%	0.03%	0.04%	0.06%	0.36%	0.00%	0.31%	0.00%
CH_4	0.00%			0.06%	0.00%	0.00%	0.003%	0.003%	0.002%	0.002%	0.00%	0.00%	0.00%
H_2S	0.00%			2.05%	0.00%	0.18%	1.73%	0.0001%	39.04%	5.98%	0.03%	1.86%	0.32%
COS	0.00%			0.01%	0.00%	0.00%	0.01%	0.00%	0.51%	0.02%	0.00%	0.03%	0.00%
CH_3OH	100.00%			0.00%	0.00%	0.00%	53.51%	64.10%	0.03%	0.00%	0.00%	0.00%	0.00%
C_3H_6	0.00%			0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NH_3	0.00%			0.00%	0.00%	0.25%	0.00%	0.00%	0.00%	7.36%	0.00%	0.00%	0.00%
HCN	0.00%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%	0.00%	0.00%	0.00%
MDEA	0.00%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	43.96%
WF_{TOC} [1]	**100.00%**			**94.03%**	**100.00%**	**2.93%**	**99.96%**	**99.95%**	**99.98%**	**82.10%**	**0.03%**	**66.85%**	**46.25%**
Percentage VOC/entire gas stream	**100.00%**	0.14%	0.29%	0.01%	**100.00%**	0.00%	**53.51%**	**64.10%**	0.54%	0.07%	0.00%	0.03%	**43.96%**

Conversion Note:
1 kg = 2.20 pound

Note:
(1) WF_{TOC} does not always equal 100% due to the presence of inerts in the area not listed in table above.

Hydrogen Energy California LLC
HECA Project

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 (@ 15 mph)
Mileage	
1-hr	1
3-hr	3
8-hr	9
24-hr	27
Annual average trucks or loads	10000

Emission Factor based on equation from AP-42, Chapter 13 (Paved Roads)

$$E = k\left(\frac{sL}{2}\right)^{0.65} \times \left(\frac{W}{3}\right)^{1.5} - C$$

E = particulate emission factor
k = particle size multiplier for particle size range and units of interest
sL = road surface silt loading
W = average weight (tons) of the vehicles traveling the road
C = emission factor for 1980's vehicle fleet exhaust, brake wear and tire wear.

Parameter	Value	Unit	
k =	0.016	lb/VMT	AP 42, Table 13.2-1.1: default k value for PM_{10}
C =	0.00047	lb/VMT	AP 42, Table 13.2-1.2: default C value for PM_{10}
sL=	0.031	g/m^2	Default value from URBEMIS 9.2 for Kern County
W =	2.65	ton	Default value from URBEMIS 9.2 for Kern County
E =	4.1E-04	lb/VMT	Estimated from the AP-42 formula
	0.19	g/VMT	

EMFAC2007 Emission Factors (g/mi) For Truck Model year 2010, Scenario year 2015

Pollutant	AERMOD	
	Gas LHDT1	Diesel LHDT2
CO	0.229	0.92
NOx	0.064	0.672
ROG	0.014	0.085
SOx	0.011	0.005
PM10 *	0.23	0.24
PM2.5	0.022	0.03

** PM10 includes entrained road dust factor for paved roads obtained from AP-42 Ch. 13, using defaults from URBEMIS 9.2*
AERMOD input assumed 2015 scenario. HARP input assumed 2040 scenario (70 years average)
HARP PM_{10} emission factor does not include tire wear or break wear contributions

1-hr Emission Rates for AERMOD (g/s) per Truck

Pollutant	AERMOD	
	Gas LHDT1	Diesel LHDT2
CO	7.26E-05	2.92E-04
NOx	2.03E-05	2.13E-04
ROG	4.44E-06	2.70E-05
SOx	3.49E-06	1.59E-06
PM10	7.21E-05	7.49E-05
PM2.5	6.98E-06	9.51E-06

3-hr Emission Rates for AERMOD (g/s) per Truck

Pollutant	AERMOD	
	Gas LHDT1	Diesel LHDT2
CO	7.26E-05	2.92E-04
NOx	2.03E-05	2.13E-04
ROG	4.44E-06	2.70E-05
SOx	3.49E-06	1.59E-06
PM10	7.21E-05	7.49E-05
PM2.5	6.98E-06	9.51E-06

8-hour Emission Rates for AERMOD (g/s) per Truck

Pollutant	AERMOD	
	Gas LHDT1	Diesel LHDT2
CO	7.26E-05	2.92E-04
NOx	2.03E-05	2.13E-04
ROG	4.44E-06	2.70E-05
SOx	3.49E-06	1.59E-06
PM10	7.21E-05	7.49E-05
PM2.5	6.98E-06	9.51E-06

24-hour Emission Rates for AERMOD (g/s) per Truck

Pollutant	AERMOD	
	Gas LHDT1	Diesel LHDT2
CO	7.26E-05	2.92E-04
NOx	2.03E-05	2.13E-04
ROG	4.44E-06	2.70E-05
SOx	3.49E-06	1.59E-06
PM10	7.21E-05	7.49E-05
PM2.5	6.98E-06	9.51E-06

Annual Emission Rates for AERMOD (g/s) per Truck

Pollutant	AERMOD	
	Gas LHDT1	Diesel LHDT2
CO	7.26E-05	2.92E-04
NOx	2.03E-05	2.13E-04
ROG	4.44E-06	2.70E-05
SOx	3.49E-06	1.59E-06
PM10	7.21E-05	7.49E-05
PM2.5	6.98E-06	9.51E-06

The HARP PM10 emission rates do not include road-entrained dust or brake and tire wear.

Calculations for Trucks Operation Modeling

Data Supplied By Client				
Parameter	**Coke and Coal Trucks (@ 10 mph)**		**Onsite Gasifier Solids Handling (@ 5 mph)**	
	Running Emissions	**Idling Emissions**	**Running Emissions**	**Idling Emissions**
Distance Traveled (mi)*	1		0.5	
Per Truck Idle Time (hr)		0.117		0.083
Maximum number of trucks or loads:				
1-hr	18	18	2	2
3-hr	54	54	7	7
8-hr	144	144	13	13
24-hr	180	180	38	37.5
Annual average trucks or loads	35,500	35,500	2,900	2,900

Emission Factor based on equation from AP-42, Chapter 13 (Paved Roads)

$$E = k\left(\frac{sL}{2}\right)^{0.65} \times \left(\frac{W}{3}\right)^{1.5} - C$$

E = particulate emission factor
k = particle size multiplier for particle size range and units of interest
sL = road surface silt loading
W = average weight (tons) of the vehicles traveling the road
C = emission factor for 1980's vehicle fleet exhaust, brake wear and tire wear.

Parameter	Value	Unit	
k =	0.016	lb/VMT	AP 42, Table 13.2-1.1: default k value for PM_{10}
C =	0.00047	lb/VMT	AP 42, Table 13.2-1.2: default C value for PM_{10}
sL=	0.031	g/m^2	Default value from URBEMIS 9.2 for Kern County
W =	2.65	ton	Default value from URBEMIS 9.2 for Kern County
E =	4.1E-04	lb/VMT	Calculated using AP-42 factors
	0.19	g/VMT	Calculated using AP-42 factors

EMFAC2007 Emission Factors (g/mi or g/idle-hour) For Truck Model year 2010, Scenario year 2015

Pollutant	Coke and Coal Trucks (@ 10 mph)		Onsite Gasifier Solids Handling (@ 5 mph)	
	Running Emissions	Idling Emissions	Running Emissions	Idling Emissions
CO	3.028	43.689	5.052	43.689
NOx	5.427	122.647	7.237	122.647
ROG	1.388	7.744	2.546	7.744
SOx	0.03	0.062	0.04	0.062
PM10 *	0.34	0.114	0.35	0.114
PM2.5	0.101	0.104	0.109	0.104

** PM10 includes entrained road dust factor for paved roads obtained from AP-42 Ch. 13, using defaults from URBEMIS 9.2*

1-hr Emission Rates for AERMOD (g/s)

Pollutant	Coke and Coal Trucks (@ 10 mph)		Onsite Gasifier Solids Handling (@ 5 mph)	
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)
CO	0.015	0.025	0.001	0.002
NOx	0.027	0.072	0.002	0.006
ROG	0.007	0.005	0.001	0.000
SOx	1.5E-04	3.6E-05	1.0E-05	2.9E-06
PM10	0.002	0.000	0.000	5.3E-06
PM2.5	0.001	0.000	3.03E-05	4.8E-06

3-hr Emission Rates for AERMOD (g/s)

Pollutant	Coke and Coal Trucks (@ 10 mph)		Onsite Gasifier Solids Handling (@ 5 mph)	
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)
CO	0.015	0.025	0.002	0.002
NOx	0.027	0.072	0.002	0.007
ROG	0.007	0.005	0.001	0.000
SOx	1.5E-04	3.6E-05	1.2E-05	3.3E-06
PM10	0.002	0.000	0.000	6.2E-06
PM2.5	0.001	0.000	3.53E-05	5.6E-06

8-hour Emission Rates for AERMOD (g/s)

Pollutant	Coke and Coal Trucks (@ 10 mph)		Onsite Gasifier Solids Handling (@ 5 mph)	
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)
CO	0.015	0.025	0.001	0.002
NOx	0.027	0.072	0.002	0.005
ROG	0.007	0.005	0.001	0.000
SOx	1.5E-04	3.6E-05	8.4E-06	2.3E-06
PM10	0.002	0.000	7.8E-05	4.3E-06
PM2.5	0.001	0.000	2.5E-05	3.9E-06

24-hour Emission Rates for AERMOD (g/s)

Pollutant	Coke and Coal Trucks (@ 10 mph)		Onsite Gasifier Solids Handling (@ 5 mph)	
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)
CO	0.006	0.011	0.001	0.002
NOx	0.011	0.030	0.002	0.004
ROG	0.003	0.002	0.001	0.000
SOx	6.3E-05	1.5E-05	8.0E-06	2.2E-06
PM10	0.001	2.8E-05	7.5E-05	4.1E-06
PM2.5	0.000	2.5E-05	2.4E-05	3.8E-06

Annual Emission Rates for AERMOD (g/s)

Pollutant	Coke and Coal Trucks (@ 10 mph)		Onsite Gasifier Solids Handling (@ 5 mph)	
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle Point)
CO	0.003	0.006	0.000	0.000
NOx	0.006	0.016	0.000	0.001
ROG	0.002	0.001	0.000	0.000
SOx	3.4E-05	8.1E-06	1.7E-06	4.8E-07
PM10	0.00038	1.5E-05	1.6E-05	8.7E-07
PM2.5	0.00011	1.4E-05	5.0E-06	8.0E-07

Hydrogen Energy California LLC 6/18/2010
HECA Project

Modeling Worst-Case 1 hr Emissions

	CTG/HRSG Maximum (1) (g/sec)	Cooling Towers (2) Power Block (g/sec/cell)	Cooling Towers (2) Process Area (g/sec/cell)	Cooling Towers (2) ASU (g/sec/cell)	Auxiliary Boiler (g/sec)	Emergency Generators (3) (g/sec/gen)	Fire Water Pump (g/sec)	Gasification Flare (g/sec)	SRU Flare (g/sec)	Rectisol Flare (g/sec)	Tg Thermal Oxidizer (g/sec)	CO_2 Vent (g/sec)	Gasifier (4) (g/sec)
NOx	21.0	--	--	--	0.1	0.4	0.2	14.9	0.544	0.005	0.3	--	0.5
CO	211.6	--	--	--	0.7	2.1	0.4	226.8	0.363	0.003	0.3	53.4	0.8
SO_2	0.9	--	--	--	0.04	0.004	0.0007	0.5980	2.33	0.0001	0.3	--	0.00
H_2S	--	--	--	--	--	--	--	--	--	--	--	0.6	--

	Feedstock DC-1 (g/sec)	Feedstock DC-2 (g/sec)	Feedstock DC-3 (g/sec)	Feedstock DC-4 (g/sec)	Feedstock DC-5 (g/sec)	Feedstock DC-6 (g/sec)	Fugitives (7) Power (g/sec)	Fugitives (7) Sru (g/sec)	Fugitives (7) SWS (g/sec)	Fugitives (7) TGTU (g/sec)	Fugitives (7) AGR (g/sec)	Fugitives (7) Gasification (g/sec)	Fugitives (7) Shift (g/sec)	Onsite LHD Truck Gas LHDT1 (g/sec)	Onsite LHD Truck Diesel LHDT2 (g/sec)	Coal & Coke Trucks (5) Running Emission (g/sec)	Coal & Coke Trucks (5) Idling Emission (g/sec)	Onsite Solid Handling Truck (6) Running Emission (g/sec)	Onsite Solid Handling Truck (6) Idling Emission (g/sec)
NOx	--	--	--	--	--	--	--	--	--	--	--	--	--	0.0000	0.0002	0.0003	0.0715	0.0000	0.0028
CO	--	--	--	--	--	--	0.0001	0.0000	0.0000	0.0003	--	0.0319	0.0053	0.0001	0.0003	0.0002	0.0255	0.0000	0.0010
SO_2	--	--	--	--	--	--	--	--	--	--	--	--	--	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2S	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

(1) HRSG modeling emission rates represents the maximum emissions rate from a composite firing scenario (all three fuels)
(2) There are three separate cooling towers. The modeling rates are per cell.
(3) There are two separate generators. Modeling rates are shown per individual generator. Assumend only one generator operates at any short term period.
(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, up to two gasifier heaters will be operational at any one time.
(5) Coal & Coke Trucks modeling rate is based on 85 separate volume sources for running emissions and one consolidated volume source for idling emissions.
(6) Gasifier Solids Handling Trucks modeling rate is based on 50 separate volume sources for running emissions and two (drop off and pick up) consolidated volume sources for idling emissions.
(7) Fugitive modeling rates were calculated per volume source as follows: Power (2), SRU (3), SWS(3), TGTU (3), Gasification (5), Shift (2)

Modeling Worst-Case 3 hr Emissions

	CTG/HRSG Maximum (1) (g/sec)	Cooling Towers (2) Power Block (g/sec/cell)	Cooling Towers (2) Process Area (g/sec/cell)	Cooling Towers (2) ASU (g/sec/cell)	Auxiliary Boiler (g/sec)	Emergency Generators (3) (g/sec/gen)	Fire Water Pump (g/sec)	Gasification Flare (g/sec)	SRU Flare (g/sec)	Rectisol Flare (g/sec)	Tg Thermal Oxidizer (g/sec)	CO_2 Vent (g/sec)	Gasifier (4) (g/sec)
SO_2	0.9	--	--	--	0.04	0.002	0.0005	0.5980	2.33	0.00	0.3	--	0.00

	Feedstock DC-1 (g/sec)	Feedstock DC-2 (g/sec)	Feedstock DC-3 (g/sec)	Feedstock DC-4 (g/sec)	Feedstock DC-5 (g/sec)	Feedstock DC-6 (g/sec)	Fugitives (7) Power (g/sec)	Fugitives (7) Sru (g/sec)	Fugitives (7) SWS (g/sec)	Fugitives (7) TGTU (g/sec)	Fugitives (7) AGR (g/sec)	Fugitives (7) Gasification (g/sec)	Fugitives (7) Shift (g/sec)	Onsite LHD Truck Gas LHDT1 (g/sec)	Onsite LHD Truck Diesel LHDT2 (g/sec)	Coal & Coke Trucks (5) Running Emission (g/sec)	Coal & Coke Trucks (5) Idling Emission (g/sec)	Onsite Solid Handling Truck (6) Running Emission (g/sec)	Onsite Solid Handling Truck (6) Idling Emission (g/sec)
SO_2	--	--	--	--	--	--	--	--	--	--	--	--	--	0.00	0.00	0.00	0.00	0.00	0.00

(1) HRSG modeling emission rates represents the maximum emissions rate from a composite firing scenario (all three fuels)
(2) There are three separate cooling towers. The modeling rates are per cell.
(3) There are two separate generators. Modeling rates are shown per individual generator. Assumend only one generator operates at any short term period.
(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, up to two gasifier heaters will be operational at any one time.
(5) Coal & Coke Trucks modeling rate is based on 85 separate volume sources for running emissions and one consolidated volume source for idling emissions.
(6) Gasifier Solids Handling Trucks modeling rate is based on 50 separate volume sources for running emissions and two (drop off and pick up) consolidated volume sources for idling emissions.
(7) Fugitive modeling rates were calculated per volume source as follows: Power (2), SRU (3), SWS(3), TGTU (3), Gasification (5), Shift (2)

Modeling Worst-Case 8 hr Emissions

	CTG/HRSG Maximum (1) (g/sec)	Cooling Towers (2) Power Block (g/sec/cell)	Cooling Towers (2) Process Area (g/sec/cell)	Cooling Towers (2) ASU (g/sec/cell)	Auxiliary Boiler (g/sec)	Emergency Generators (3) (g/sec/gen)	Fire Water Pump (g/sec)	Gasification Flare (g/sec)	SRU Flare (g/sec)	Rectisol Flare (g/sec)	Tg Thermal Oxidizer (g/sec)	CO_2 Vent (g/sec)	Gasifier (4) (g/sec)
CO	89.3	--	--	--	0.7	0.53	0.1	226.8	2.328	0.003	0.3	53.4	0.8

	Feedstock DC-1 (g/sec)	Feedstock DC-2 (g/sec)	Feedstock DC-3 (g/sec)	Feedstock DC-4 (g/sec)	Feedstock DC-5 (g/sec)	Feedstock DC-6 (g/sec)	Fugitives (7) Power (g/sec)	Fugitives (7) Sru (g/sec)	Fugitives (7) SWS (g/sec)	Fugitives (7) TGTU (g/sec)	Fugitives (7) AGR (g/sec)	Fugitives (7) Gasification (g/sec)	Fugitives (7) Shift (g/sec)	Onsite LHD Truck Gas LHDT1 (g/sec)	Onsite LHD Truck Diesel LHDT2 (g/sec)	Coal & Coke Trucks (5) Running Emission (g/sec)	Coal & Coke Trucks (5) Idling Emission (g/sec)	Onsite Solid Handling Truck (6) Running Emission (g/sec)	Onsite Solid Handling Truck (6) Idling Emission (g/sec)
CO	--	--	--	--	--	--	0.0001	0.0000	0.0000	0.0003	--	0.0319	0.0053	0.0	0.0	0.0	0.0	0.0	0.0

(1) HRSG modeling emission rates represents the maximum emissions rate from a composite firing scenario (all three fuels)
(2) There are three separate cooling towers. The modeling rates are per cell.
(3) There are two separate generators. Modeling rates are shown per individual generator. Assumend only one generator operates at any short term period.
(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, up to two gasifier heaters will be operational at any one time.
(5) Coal & Coke Trucks modeling rate is based on 85 separate volume sources for running emissions and one consolidated volume source for idling emissions.
(6) Gasifier Solids Handling Trucks modeling rate is based on 50 separate volume sources for running emissions and two (drop off and pick up) consolidated volume sources for idling emissions.
(7) Fugitive modeling rates were calculated per volume source as follows: Power (2), SRU (3), SWS(3), TGTU (3), Gasification (5), Shift (2)

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Modeling Worst-Case 24 Hour Emission Rate

	CTG/HRSG Maximum [1] (g/sec)	Cooling Towers [2] Power Block (g/sec/cell)	Cooling Towers [2] Process Area (g/sec/cell)	Cooling Towers [2] ASU (g/sec/cell)	Auxiliary Boiler (g/sec)	Emergency Generators [3] (g/sec/gen)	Fire Water Pump (g/sec)	Gasification Flare (g/sec)	SRU Flare (g/sec)	Rectisol Flare (g/sec)	Tg Thermal Oxidizer (g/sec)	CO_2 Vent (g/sec)	Gasifier [4] (g/sec)
SO_2	0.9	--	--	--	0.04	0.0003	0.0001	0.5980	1.1639	0.0001	0.3	--	0.00
PM_{10}	2.5	0.038	0.030	0.028	0.09	0.005	0.0002	0.0002	0.0069	0.0001	0.01	--	0.02
$PM_{2.5}$ [5]	2.5	0.023	0.018	0.017	0.09	0.005	0.0002	0.0002	0.0069	0.0001	0.01	--	0.02

	Feedstock DC-1 (g/sec)	Feedstock DC-2 (g/sec)	Feedstock DC-3 (g/sec)	Feedstock DC-4 (g/sec)	Feedstock DC-5 (g/sec)	Feedstock DC-6 (g/sec)	Fugitives [8] Power (g/sec)	Fugitives [8] Sru (g/sec)	Fugitives [8] SWS (g/sec)	Fugitives [8] TGTU (g/sec)	Fugitives [8] AGR (g/sec)	Fugitives [8] Gasification (g/sec)	Fugitives [8] Shift (g/sec)	Onsite LHD Truck Gas LHDT1 (g/sec)	Onsite LHD Truck Diesel LHDT2 (g/sec)	Coal & Coke Trucks [6] Running Emission (g/sec)	Coal & Coke Trucks [6] Idling Emission (g/sec)	Onsite Solid Handling Truck [7] Running Emission (g/sec)	Onsite Solid Handling Truck [7] Idling Emission (g/sec)
SO_2	--	--	--	--	--	--	--	--	--	--	--	--	--	0.00	0.00	0.00	0.00	0.00	0.00
PM_{10}	0.030	0.076	0.041	0.026	0.025	0.003	--	--	--	--	--	--	--	0.00	0.00	0.00	0.00	0.00	0.00
$PM_{2.5}$ [5]	0.009	0.022	0.012	0.008	0.007	0.001	--	--	--	--	--	--	--	0.00	0.00	0.00	0.00	0.00	0.00

(1) HRSG modeling emission rates represents the maximum emissions rate from a composite firing scenario (all three fuels)
(2) There are three separate cooling towers. The modeling rates are per cell.
(3) There are two separate generators. Modeling rates are shown per individual generator. Assumend only one generator operates at any short term period.
(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, up to two gasifier heaters will be operational at any one time.
(5) Where $PM_{10} = PM_{2.5}$, it is assumed that PM_{10} is 100% $PM_{2.5}$
(6) Coal & Coke Trucks modeling rate is based on 85 separate volume sources for running emissions and one consolidated volume source for idling emissions.
(7) Gasifier Solids Handling Trucks modeling rate is based on 50 separate volume sources for running emissions and two (drop off and pick up) consolidated volume sources for idling emissions.
(8) Fugitive modeling rates were calculated per volume source as follows: Power (2), SRU (3), SWS(3), TGTU (3), Gasification (5), Shift (2)

Modeling Annual Average Emission Rate

	CTG/HRSG Maximum [1] (g/sec)	Cooling Towers [2] Power Block (g/sec/cell)	Cooling Towers [2] Process Area (g/sec/cell)	Cooling Towers [2] ASU (g/sec/cell)	Auxiliary Boiler (g/sec)	Emergency Generators [3] (g/sec/gen)	Fire Water Pump (g/sec)	Gasification Flare (g/sec)	SRU Flare (g/sec)	Rectisol Flare (g/sec)	Tg Thermal Oxidizer (g/sec)	CO_2 Vent (g/sec)	Gasifier [4] (g/sec)
NO_X	4.8	--	--	--	0.03	0.002	0.003	0.2	0.007	0.005	0.3	--	0.07
CO	4.5	--	--	--	0.2	0.013	0.005	3.2	0.005	0.003	0.25	3.1	0.10874
VOC	1.0	--	--	--	0.02	0.0014	0.0002	0.0001	0.00008	0.00005	0.01	0.1	0.02175
SO_2	0.8	--	--	--	0.01	0.00002	0.00001	0.0034	0.0107	0.0001	0.2	--	0.00063
PM_{10}	2.4	0.036	0.028	0.027	0.02	0.0003	0.00003	0.0002	0.0002	0.0001	0.01	--	0.002
$PM_{2.5}$ [5]	2.4	0.022	0.017	0.016	0.02	0.0003	0.00003	0.0002	0.0002	0.0001	0.01	--	0.002
H_2S	--	--	--	--	--	--	--	--	--	--	--	0.0	--

	Feedstock DC-1 (g/sec)	Feedstock DC-2 (g/sec)	Feedstock DC-3 (g/sec)	Feedstock DC-4 (g/sec)	Feedstock DC-5 (g/sec)	Feedstock DC-6 (g/sec)	Fugitives [8] Power (g/sec)	Fugitives [8] Sru (g/sec)	Fugitives [8] SWS (g/sec)	Fugitives [8] TGTU (g/sec)	Fugitives [8] AGR (g/sec)	Fugitives [8] Gasification (g/sec)	Fugitives [8] Shift (g/sec)	Onsite LHD Truck Gas LHDT1 (g/sec)	Onsite LHD Truck Diesel LHDT2 (g/sec)	Coal & Coke Trucks [5] Running Emission (g/sec)	Coal & Coke Trucks [5] Idling Emission (g/sec)	Onsite Solid Handling Truck [6] Running Emission (g/sec)	Onsite Solid Handling Truck [6] Idling Emission (g/sec)
NO_X	--	--	--	--	--	--	--	--	--	--	--	--	--	0.00002	0.00021	0.00	0.02	0.00	0.00
CO	--	--	--	--	--	--	0.0001	0.0000	0.0000	0.0003	--	0.0319	0.0053	0.00007	0.00029	0.00004	0.00574	0.00000	0.00017
VOC	--	--	--	--	--	--	-- [9]	-- [9]	-- [9]	0.128	0.061	-- [9]	-- [9]	0.00000	0.00003	0.00002	0.00102	0.00000	0.00003
SO_2	--	--	--	--	--	--	--	--	--	--	--	--	--	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000
PM_{10}	0.006	0.015	0.036	0.023	0.022	0.0004	--	--	--	--	--	--	--	0.00007	0.00007	0.00000	0.00001	0.00000	0.00000
$PM_{2.5}$ [5]	0.002	0.004	0.011	0.0068	0.007	0.0001	--	--	--	--	--	--	--	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
H_2S	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

(1) HRSG modeling emission rates represents the maximum emissions rate from a composite firing scenario (all three fuels)
(2) There are three separate cooling towers. The modeling rates are per cell.
(3) There are two separate generators. Modeling rates are shown per individual generator. Assumend two generators operates during the year.
(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, up to two gasifier heaters will be operational at any one time. Annual model was based on the 3 gasifier heaters operations (1200 hours each)
(5) Where $PM_{10} = PM_{2.5}$, it is assumed that PM_{10} is 100% $PM_{2.5}$
(6) Coal & Coke Trucks modeling rate is based on 85 separate volume sources for running emissions and one consolidated volume source for idling emissions.
(7) Gasifier Solids Handling Trucks modeling rate is based on 50 separate volume sources for running emissions and two (drop off and pick up) consolidated volume sources for idling emissions.
(8) Fugitive modeling rates were calculated per volume source as follows: Power (2), SRU (3), SWS(3), TGTU (3), Gasification (5), Shift (2)
(9) Per District policy (SSP-2015), VOC emissions are not assessed to components handling fluid streams with a VOC content of 10% of less by weight. Therefore, VOC emissions from Area # 2, 3, 4, 6, 9, 10, 11, and 12 were not included in the emission rate calculation.

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Parameter		CTG/HRSG , H2-rich Fuel 100% Load (2)	CTG/HRSG , H2-rich Fuel 80% Load	CTG/HRSG , H2-rich Fuel 60% Load	CTG/HRSG , Natural Gas Fuel 100% Load(3)	CTG/HRSG , Natural Gas Fuel 80% Load	CTG/HRSG , Natural Gas Fuel 60% Load	CTG/HRSG Co-Firing ** 100% Load
English Units								
Stack height above grade(1)	ft	213	213	213	213	213	213	213
Stack diameter	ft	20	20	20	20	20	20	20
Stack outlet temperature	°F	200	190	180	180	170	160	190
Stack exit flow, act	ft^3/s	19,900	16,300	13,400	16,700	14,300	11,900	18,300
Metric Units								
Stack height above grade(1)	m	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Stack diameter	m	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Stack outlet temperature	K	366.5	360.9	355.4	355.4	349.8	344.3	360.9
Stack exit flow, act	m^3/s	563.5	461.6	379.4	472.9	404.9	337.0	518.2
Stack Area	m^2	29.2	29.2	29.2	29.2	29.2	29.2	29.2
Stack exit velocity, act	m/s	19.3	15.8	13.0	16.2	13.9	11.5	17.8

Parameter		Aux Boiler	Gasification Flare(4)	SRU Flare(6)	Rectisol Flare (6)	Tail Gas Oxidizer(7)	Gasifier Warming Vent (ea.)	Cooling Towers (per cell)(5)	Diesel Generator (ea.)	Fire Pump Engine	CO_2 Vent
English Units											
Stack height above grade(1)	ft	80	250	250	250	165	210	55	20	20	260
Stack diameter	ft	4.5	(NA)	(NA)	(NA)	2.5	1.0	30	1.2	0.7	3.5
Stack outlet temperature	°F	300	(NA)	(NA)	(NA)	1200	150	75	760	850	65
Stack exit flow, act	ft^3/s	480	(NA)	(NA)	(NA)	120	68	18,500	250	60	1,765
Metric Units											
Stack height above grade(1)	m	24.4	76.2	76.2	76.2	50.3	64.0	16.8	6.1	6.1	79.2
Stack diameter	m	1.4	5.5	1.1	0.1	0.8	0.3	9.1	0.4	0.2	1.1
Stack outlet temperature	K	422.0	1273	1273	1273	922.0	338.7	297.0	677.6	727.6	291.5
Stack exit flow, act	m^3/s	13.6	469.5	18.8	0.2	3.4	1.9	523.9	7.1	1.7	50.0
Stack Area	m^2	1.5	23.5	0.9	0.01	0.5	0.1	65.7	0.1	0.04	0.9
Stack exit velocity, act	m/s	9.2	20.0	20.0	20.0	7.5	26.4	8.0	67.4	47.5	55.9

Notes:
(1) Minimum stack height assumed for worst-case dispersion.
(2) Volume Flow Value shown in table for H2-rich fuel is based on full load syn gas combustion (relatively constant for varying ambient temperatures). Duct firing of the HSRG changes the stack volumetric flow by about 1% or less.
(3) Full load stack flow for natural gas combustion will vary from the value shown in the table during warm summer ambient temperatures to about 18,000 act ft3/sec for winter ambient temperatures. Stack flow rates for co-firing of H2-rich gas and natural gas will range between the values shown for the two fuels separately.
(4) Stack parameters estimated from gasifier startup.
(5) Thirteen cells estimated for power block cooling tower; four cells estimated for process cooling tower, and four cells estimated for the ASU cooling tower.
(6) Waste gas heat release, 10^6 Btu/hr, HHV. First exit flow value is from maximum startup heat release. Rectisol Flare has no planned operation just standby with pilot on.
(7) Estimated oxidizer stack outlet flow for normal operating case of miscellaneous vent gas disposal; SRU startup case will be about 50% greater.
** HRSG Stack Cofiring is estimated assuming 47% Syngas and the balance natural gas

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		Feed Stock - Dust Collection Units					
Parameter		DC-1	DC-2	DC-3	DC-4	DC-5	DC-6
English Units							
Ground elevation	ft	289	289	289	289	289	289
Stack elevation	ft	334	459	465	459	368	465
Stack height above grade	ft	46	171	177	171	80	177
Stack diameter	ft	1.7	2.7	1.8	1.4	1.4	0.8
Stack outlet temperature (1)	°F	Ambient	Ambient	Ambient	Ambient	Ambient	Ambient
Stack exit flow, act	ft^3/s	108	273	127	81	78	21
Metric Units							
Stack height above grade	m	13.9	52.0	53.8	52.0	24.2	53.8
Stack diameter	m	0.5	0.8	0.6	0.4	0.4	0.2
Stack outlet temperature (1)	K	Ambient	Ambient	Ambient	Ambient	Ambient	Ambient
Stack exit flow, act	m^3/s	3.1	7.7	3.6	2.3	2.2	0.6
Stack Area	m^2	0.2	0.5	0.2	0.1	0.1	0.0
Stack exit velocity, act	m/s	15.1	14.9	14.7	15.7	15.1	14.2

(1) Assume ambient temperature

		Fugitive Emissions						
Parameter		Power	SRU	SWS	TGTU	Gasification	Shift	AGR
Metric Units								
Ground elevation	m	87.93	87.93	87.93	87.93	87.93	87.93	87.93
Number of Volume Sources		2	3	3	3	5	2	3
Release height above grade	m	7.62	6.10	6.10	6.10	30.48	6.10	6.10
Horizontal Dimension	m	3.433	6.353	6.353	7.995	7.200	16.512	5.116
Vertical Dimension	m	7.1	5.7	5.7	5.7	28.4	5.7	5.7

APPENDIX B
HECA OPERATIONAL GREENHOUSE GAS EMISSIONS

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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

CO_2 =	52.78	kg/MMBtu =	116.36	lb/MMBtu
CH_4 =	0.0059	kg/MMBtu =	0.013	lb/MMBtu
N_2O =	0.0001	kg/MMBtu =	0.00022	lb/MMBtu

Diesel GHG Emission Factors

CO_2 =	10.15	kg/gal =	22.38	lb/gal
CH_4 =	0.0003	kg/gal =	0.001	lb/gal
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 2.2 (March 2007)

HRSG Stack

Operating Hours	832	hr/yr				
HRSG Heat Input	2,548	MMBtu/hr				
CO_2 =	111,921	tonne/yr				
CH_4 =	13	tonne/yr =	263	tonne CO_2e/yr		
N_2O =	0.21	tonne/yr =	66	tonne CO_2e/yr	Total tonne CO_2e/yr =	112,249

During mature operation of the HRSG, the unit will fire only syngas, except during periods of startup and shutdown.

Startup and shutdown of the HRSG will be accomplished using natural gas. The total operating hours, including startup and shutdown are estimated at 823 hr/yr for the worst case GHG emissions from natural gas combustion in the HRSG. The total startup and shutdown duration are estimated at 65 hr/yr for the worst case criteria pollutant.

HRSG heat input rate is assumed to be the maximum heat input rate firing natural gas with duct burner, which corresponds to winter minimum (20 F).

HRSG Stack - Burning Hydrogen-Rich Fuel

Operating Hours	7,490	hr/yr		
HRSG Heat Input	2,422	MMBtu/hr		
CO_2 =	231,144	tonne/yr	Total tonne CO_2e/yr =	231,144

Syngas GHG Emission Factors

CO_2 =	28.1	lb/MMBtu

During mature operation of the HRSG, the unit will fire only syngas, except during periods of startup and shutdown.

HRSG heat input rate is assumed to be the maximum heat input rate firing syngas with duct burner.

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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.

Auxiliary Boiler

Operating Hours		2,190	hr/yr			
Heat Input		142	MMBtu/hr			
CO_2 =	16,418	tonne/yr				
CH_4 =	2	tonne/yr =	39	tonne CO_2e/yr		
N_2O =	0.03	tonne/yr =	10	tonne CO_2e/yr	Total tonne CO_2e/yr =	16,466

Emergency Generators (2)

Operating Hours		52	hr/yr			
Heat Input		2,800	Bhp			
CO_2 =	3,201	lb/hr =	76	tonne CO_2/yr		
CH_4 =	0.09	lb/hr =	0.047	tonne CO_2e/yr		
N_2O =	0.03	lb/hr =	0.2307	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 =	0.02	lb/hr =	0.018	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.

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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.

Gasification Flare

Pilot Operation						
Operating Hours		8,760	hr/yr			
Heat Input		0.5	MMBtu/hr			
CO_2 =	231	tonne/yr				
CH_4 =	0.03	tonne/yr =	0.5	tonne CO_2e/yr		
N_2O =	0.0004	tonne/yr =	0.1	tonne CO_2e/yr	Total tonne CO_2e/yr =	232
Flaring Events						
Total Operation		196,900	MMBtu/yr			
CO_2 =	10,395	tonne/yr				
CH_4 =	1.2	tonne/yr =	24	tonne CO_2e/yr		
N_2O =	0.02	tonne/yr =	6	tonne CO_2e/yr	Total tonne CO_2e/yr =	10,426

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 =	0.02	tonne/yr =	0.3	tonne CO_2e/yr		
N_2O =	0.0003	tonne/yr =	0.08	tonne CO_2e/yr	Total tonne CO_2e/yr =	139

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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.

SRU Flare

Pilot Operation						
Operating Hours	8,760	hr/yr				
Heat Input	0.3	MMBtu/hr				
CO_2 =	139	tonne/yr				
CH_4 =	0.02	tonne/yr =	0.3	tonne CO_2e/yr		
N_2O =	0.0003	tonne/yr =	0.08	tonne CO_2e/yr	Total tonne CO_2e/yr =	139
Flaring Events (natural gas assist)						
Operating Hours	40	hr/yr				
Heat Input	36	MMBtu/hr				
CO_2 =	76	tonne/yr				
CH_4 =	0.008	tonne/yr =	0.18	tonne CO_2e/yr		
N_2O =	0.00014	tonne/yr =	0.045	tonne CO_2e/yr	Total tonne CO_2e/yr =	76
Throughput (inerts)						
H_2S =	25	%				
CO_2 (inerts) =	75	%				
H_2S =	72	lbmol/hr				
CO_2 (inerts) =	216	lbmol/hr				
CO_2 (inerts) =	9,488	lb/hr				
Operating Hours	40	hr/yr				
					Total tonne CO_2e/yr =	172

Throughtput (inerts) amount calculated from the relationship of CO2 to H2S in the SRU Flare.

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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.

Tail Gas Thermal Oxidizer

Process Vent Disposal Emissions						
Operating Hours	8,460	hr/yr				
Heat Input	10	MMBtu/hr				
CO_2 =	4,466	tonne/yr				
CH_4 =	0.50	tonne/yr =	10.5	tonne CO_2e/yr		
N_2O =	0.0085	tonne/yr =	2.6	tonne CO_2e/yr	Total tonne CO_2e/yr =	4,480
SRU Startup Waste Gas Disposal						
Operating Hours	300	hr/yr				
Heat Input	10	MMBtu/hr				
CO_2 =	158	tonne/yr				
CH_4 =	0.018	tonne/yr =	0.37	tonne CO_2e/yr		
N_2O =	0.00030	tonne/yr =	0.093	tonne CO_2e/yr	Total tonne CO_2e/yr =	159

GHG emissions from thermal oxidizer are estimated using GHG emission factors for natural gas combustion for the assist gas.

Gasifier Refractory Heaters

Operating Hours	3,600	hr/yr				
Heat Input	18	MMBtu/hr				
CO_2 =	3,421	tonne/yr				
CH_4 =	0	tonne/yr =	8	tonne CO_2e/yr		
N_2O =	0.01	tonne/yr =	2	tonne CO_2e/yr	Total tonne CO_2e/yr *=	3,431

*Assumed 3,600 hours of annual normal operation (3 heaters with 1,200 hr/yr of operation for each gasifier)

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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.

Intermittent CO_2 Vent

Operating Hours	504	hr/yr
CO_2 Emission Rate	656,000	lb/hr
Total tonne CO_2e/yr =	150,011	

Assumes 504 hours per year venting at full rate.

Fugitives

Operating Hours		8,760	hr/yr	
CO_2 =	40	tpy	38.60	tonne CO_2e/yr
CH_4 =	0.02	tpy	0.46	tonne CO_2e/yr
Total tonne CO_2e/yr =	39			

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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.

230 kV Circuit Breakers

Number of Circuit Breakers		10				
SF_6 capacity		216	lb/breaker			
Annual Leakage rate		1%				
SF_6 =	0.010	tonne/yr =	234	tonne CO_2e/yr	Total tonne CO_2e/yr =	234

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		1%				
SF_6 =	0.001	tonne/yr =	16	tonne CO_2e/yr	Total tonne CO_2e/yr =	16

SF6 GWP = 23,900 http://www.epa.gov/electricpower-sf6/faq.html)
Sources: SF6 inventory and maximum leakage rates from electrical equipment suppliers

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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 =	0.012	g/mi
				EF N_2O =	0.0101	g/mi
CO_2 =	118	tonne/yr				
CH_4 =	1.20E-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

Running emission Factor for N2O is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for 2010 model year light 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 =	0.004	g/mi
				EF N_2O =	0.0015	g/mi
CO_2 =	52	tonne/yr				
CH_4 =	4.00E-04	tonne/yr =	8.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

Running emission Factor for N2O is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for 2010 model year light trucks.

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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.

Coal and Coke Trucks

Number of Truck loads	35,500	truck loads		EF CO_2 =	3,165	g/mi
Distrance Travelled Onsite	1	mi/ load		EF CH_4 =	0.064	g/mi
Truck Idle Time	0.117	hr/load		EF N_2O =	0.0048	g/mi
				EF CO_2 =	6,542	g/ idle hr
				EF CH_4 =	0.360	g/ idle hr
				EF N_2O =	0.027	g/ idle hr

CO_2 =	140	tonne/yr				
CH_4 =	3.77E-03	tonne/yr =	8.E-02	tonne CO_2e/yr		
N_2O =	2.83E-04	tonne/yr =	9.E-02	tonne CO_2e/yr	Total tonne CO_2e/yr =	140

Running emission Factor for N2O is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for 2010 model year diesel heavy duty vehicles. Idling emission Factor for N2O was extrapolated based on the ratio of CH4 emission factor for running and idling.

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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 Gasifier Solids Handling

Number of Truck loads	2,900	truck loads	EF CO_2 =	3,845	g/mi
Distrance Travelled Onsite	0.5	mi/ load	EF CH_4 =	0.118	g/mi
Truck Idle Time	0.083	hr/load	EF N_2O =	0.0048	g/mi
			EF CO_2 =	6,542	g/ idle hr
			EF CH_4 =	0.360	g/ idle hr
			EF N_2O =	0.015	g/ idle hr

CO_2 =	7	tonne/yr				
CH_4 =	2.58E-04	tonne/yr =	5.E-03	tonne CO_2e/yr		
N_2O =	1.05E-05	tonne/yr =	3.E-03	tonne CO_2e/yr	Total tonne CO_2e/yr =	7

Running emission Factor for N2O is based on Table C.4, California Climate Action Registry General Reporting Protocol Version 3.1, Jan 2009 for 2010 model year diesel heavy duty vehicles. Idling emission Factor for N2O was extrapolated based on the ratio of CH4 emission factor for running and idling.

Total tonne CO_2e/yr for Stationary Sources=	**529,594**
Total tonne CO_2e/yr for Mobile Sources=	**317**
Total tonne CO_2e/yr for All Operations=	**529,911**

APPENDIX C
HECA OPERATIONAL TOXIC AIR CONTAMINANT EMISSIONS

Project Total HAP Emissions Summary

Hydrogen Energy California LLC *6/18/2010*
HECA Project

Compound	CAS #	Annual Rate (tons per year)	CTG/HRSG Syngas	Cooling Tower (Power Block)	Cooling Tower (Process Area)	Cooling Tower (ASU)	Auxiliary Boiler	Emergency Generators (2)	Fire Water Pump	Gasification Flare	SRU Flare	Rectisol Flare	Tg Thermal Oxidizer	CO_2 Vent	Gasifier Warming (3)	Onsite LHD Truck (10)	Coal& Solids Trucks	Fugitive
1,3-Butadiene	106-99-0	0.00E+00																
Acetaldehyde	75-07-0	2.24E-02	1.82E-02							4.12E-03	8.33E-05							
Acrolein	107-02-8	9.78E-04								9.58E-04	1.94E-05							
Ammonia*	7664-41-7	7.71E+01	7.66E+01				3.42E-01											0.17
Antimony	7440-36-0	1.11E-02	1.11E-02															
Arsenic	7440-38-2	2.44E-02	2.43E-02	4.69E-05	1.13E-05	1.08E-05	2.96E-05			1.92E-05	3.87E-07	2.58E-07	8.34E-06		6.17E-06			
Barium	7440-39-3	5.67E-06										5.67E-06						
Benzene	71-43-2	4.03E-02	2.43E-02				3.11E-04			1.52E-02	3.08E-04	2.71E-06	8.76E-05		6.48E-05			
Beryllium	7440-41-7	2.64E-03	2.63E-03				1.78E-06			1.15E-06	2.32E-08	1.55E-08	5.01E-07		3.70E-07			
Cadmium	7440-43-9	9.75E-02	9.72E-02				1.63E-04			1.05E-04	2.13E-06	1.42E-06	4.59E-05		3.39E-05			
Carbon Disulfide	75-15-0	4.66E-01	4.66E-01															
Carbonyl Sulfide	463-58-1	9.91E+00												9.86E+00				4.81E-02
Chromium	7440-47-3	2.40E-04								1.34E-04	2.71E-06	1.80E-06	5.84E-05		4.32E-05			
Chromium, (hexavalent)	18540-29-9	1.55E-03	1.55E-03															
Chromium, Total	0-00-5	5.37E-03	5.16E-03				2.07E-04											
Cobalt	7440-48-4	2.66E-03	2.63E-03				1.24E-05			8.05E-06	1.63E-07	1.08E-07	3.50E-06		2.59E-06			
Copper*	7440-50-8	2.85E-04		9.10E-06	2.20E-06	2.09E-06	1.26E-04			8.15E-05	1.65E-06	1.10E-06	3.55E-05		2.62E-05			
Cyanides	57-12-5	6.28E-02	5.77E-02															5.06E-03
Ethylbenzene	100-41-4	1.41E-01								1.38E-01	2.80E-03							
Fluoride*		1.21E-03		8.19E-04	1.98E-04	1.88E-04												
Formaldehyde	50-00-0	3.03E-01	1.72E-01				1.11E-02			1.12E-01	2.26E-03	9.66E-05	3.13E-03		2.31E-03			
Hexane	110-54-3	4.00E-01					2.67E-01					2.32E-03	7.51E-02		5.55E-02			
Hydrochloric Acid	7647-01-0	1.32E-01	1.32E-01															
Hydrogen Fluoride (hydrofluoric acid)	7664-39-3	5.06E-01	5.06E-01															
Hydrogen Sulfide	7783-06-4	3.72E+00												1.30E+00				2.42
Lead	7439-92-1	5.72E-03	5.67E-03							4.79E-05	9.69E-07							
Manganese	7439-96-5	1.41E-02	1.05E-02	2.34E-03	5.66E-04	5.38E-04	5.63E-05			3.64E-05	7.36E-07	4.90E-07	1.59E-05		1.17E-05			
Mercury	7439-97-6	1.22E-02	1.21E-02				3.85E-05			2.49E-05	5.04E-07	3.35E-07	1.08E-05		8.02E-06			
Methanol	67-56-1	7.09E+00																7.09E+00
Methyl Bromide (Bromomethane)	74-83-9	4.83E-01	4.83E-01															
Methylene Chloride (Dichloromethane)	75-09-2	2.23E-02	2.23E-02															
Naphthalene	91-20-3	2.65E-02	2.53E-02				9.03E-05			1.05E-03	2.13E-05	7.86E-07	2.54E-05		1.88E-05			
n-Hexane	110-54-3	2.84E-03								2.78E-03	5.62E-05							
Nickel	7440-02-0	4.62E-03	3.95E-03				3.11E-04			2.01E-04	4.07E-06	2.71E-06	8.76E-05		6.48E-05			
Phenol	108-95-2	3.73E-01	3.73E-01															
Propylene*	115-07-1	6.57E+00								2.34E-01	4.73E-03							6.33E+00
Propylene Oxide	75-56-9	0.00E+00																
Selenium	7782-49-2	5.73E-03	5.67E-03	3.90E-05	9.42E-06	8.95E-06	3.55E-06			2.30E-06	4.65E-08	3.09E-08	1.00E-06		7.41E-07			
Sulfuric Acid and Sulfates*	7664-93-9	5.79E+00	5.79E+00															
Toluene	108-88-3	6.76E-03	3.34E-04				5.03E-04			5.56E-03	1.12E-04	4.38E-06	1.42E-04		1.05E-04			
Vanadium*	7440-62-2	7.35E-04					3.41E-04			2.20E-04	4.46E-06	2.96E-06	9.59E-05		7.10E-05			
Xylenes	1330-20-7	2.84E-03								2.78E-03	5.62E-05							
Diesel Particulate Matter*	DPM	3.22E-02						2.39E-02	9.19E-04							3.42E-03	3.94E-03	
2-Methylnaphthalene	PAH	5.33E-06					3.55E-06					3.09E-08	1.00E-06		7.41E-07			
3-Methylchloranthrene	PAH	4.00E-07					2.67E-07					2.32E-09	7.51E-08		5.55E-08			
7,12-Dimethylbenz(a)anthracene	PAH	3.55E-06					2.37E-06					2.06E-08	6.67E-07		4.94E-07			
Acenaphthene	PAH	4.00E-07					2.67E-07					2.32E-09	7.51E-08		5.55E-08			
Acenaphthylene	PAH	4.00E-07					2.67E-07					2.32E-09	7.51E-08		5.55E-08			
Anthracene	PAH	5.33E-07					3.55E-07					3.09E-09	1.00E-07		7.41E-08			
Benz(a)anthracene	PAH	2.34E-05	2.33E-05									2.32E-09	7.51E-08		5.55E-08			
Benzo(a)anthracene	PAH	2.67E-07					2.67E-07											
Benzo(a)pyrene	PAH	2.66E-07					1.78E-07					1.55E-09	5.01E-08		3.70E-08			
Benzo(b)fluoranthene	PAH	4.00E-07					2.67E-07					2.32E-09	7.51E-08		5.55E-08			
Benzo(g,h,i)perylene	PAH	2.66E-07					1.78E-07					1.55E-09	5.01E-08		3.70E-08			
Benzo(k)fluoranthene	PAH	4.00E-07					2.67E-07					2.32E-09	7.51E-08		5.55E-08			
Chrysene	PAH	4.00E-07					2.67E-07					2.32E-09	7.51E-08		5.55E-08			
Dibenzo(a,h)anthracene	PAH	2.66E-07					1.78E-07					1.55E-09	5.01E-08		3.70E-08			
Dichlorobenzene	PAH	1.55E-06										1.55E-06						
Fluoranthene	PAH	6.66E-07					4.44E-07					3.86E-09	1.25E-07		9.26E-08			
Fluorene	PAH	6.21E-07					4.15E-07					3.61E-09	1.17E-07		8.64E-08			
Indeno(1,2,3-cd)pyrene	PAH	4.00E-07					2.67E-07					2.32E-09	7.51E-08		5.55E-08			
PAH (excluding Naphthalene)	PAH	2.93E-04								2.88E-04	5.81E-06							
Phenanathrene	PAH	3.77E-06					2.52E-06					2.19E-08	7.09E-07		5.25E-07			
Pyrene	PAH	1.11E-06					7.40E-07					6.44E-09	2.09E-07		1.54E-07			
Total Combined HAPs and TACs		**113.36**	**84.81**	**3.26E-03**	**7.87E-04**	**7.48E-04**	**6.22E-01**	**2.39E-02**	**9.19E-04**	**5.18E-01**	**1.05E-02**	**2.44E-03**	**7.88E-02**	**1.12E+01**	**5.83E-02**	**3.42E-03**	**3.94E-03**	**1.61E+01**
Total HAPs*		**23.90**	**2.46**	**2.43E-03**	**5.87E-04**	**5.58E-04**	**2.79E-01**	**0.00E+00**	**0.00E+00**	**2.84E-01**	**5.74E-03**	**2.44E-03**	**7.87E-02**	**1.12E+01**	**5.82E-02**	**0.00E+00**	**0.00E+00**	**9.56E+00**

Notes:

* 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.

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Annual emissions based on 100 percent load at annual average temperature (65°F)

HRSG Heat Input (Yearly Average - 65°F) =	2,159.00	10^6 Btu/hr (higher heating value)
Duct Burner Heat Input (Yearly Average - 65°F) =	273.76	10^6 Btu/hr ((higher heating value)
Total HRSG Heat Input (Yearly Average - 65°F) =	2,432.76	10^6 Btu/hr ((higher heating value)

Hourly emissions based on 100 percent load at winter minimum temperature (20°F)

HRSG Heat Input (Winter Minimum - 20°F) =	2,176.00	10^6 Btu/hr ((higher heating value)
Duct Burner Heat Input (Winter Minimum - 20°F) =	273.76	10^6 Btu/hr ((higher heating value)
Total HRSG Heat Input (Winter Minimum - 20°F) =	2,449.76	10^6 Btu/hr ((higher heating value)
HRSG (Firing Syngas) Operating Hours =	8,322.0	hr/yr

Compound	CAS #	Emission Factor (lb/10^{12} Btu coal)	Hourly (lb/hr)	Annual (lb/yr)
Acetaldehyde	75-07-0	1.8	4.41E-03	3.64E+01
Ammonia	7664-41-7		1.84E+01	1.53E+05
Antimony	7440-36-0	1.1	2.69E-03	2.23E+01
Arsenic	7440-38-2	2.4	5.88E-03	4.86E+01
Benz[a]anthracene	56-55-3	0.0023	5.63E-06	4.66E-02
Benzene	71-43-2	2.4	5.88E-03	4.86E+01
Beryllium	7440-41-7	0.26	6.37E-04	5.26E+00
Cadmium	7440-43-9	9.6	2.35E-02	1.94E+02
Carbon disulfide	75-15-0	46	1.13E-01	9.31E+02
Chromium (hexavalent)	18540-29-9	0.15	3.75E-04	3.10E+00
Chromium, total	0-00-5	0.51	1.25E-03	1.03E+01
Cobalt	7440-48-4	0.26	6.37E-04	5.26E+00
Cyanides	57-12-5	5.7	1.40E-02	1.15E+02
Formaldehyde	50-00-0	17	4.16E-02	3.44E+02
Hydrochloric acid	7647-01-0	13	3.18E-02	2.63E+02
Hydrogen fluoride (Hydrofluoric acid)	7664-39-3	50	1.22E-01	1.01E+03
Lead	7439-92-1	0.56	1.37E-03	1.13E+01
Manganese	7439-96-5	1.0	2.55E-03	2.11E+01
Mercury	7439-97-6	1.2	2.94E-03	2.43E+01
Methyl bromide (Bromomethane)	74-83-9	47.7	1.17E-01	9.66E+02
Methylene chloride (Dichloromethane)	75-09-2	2.2	5.39E-03	4.45E+01
Naphthalene	91-20-3	2.5	6.12E-03	5.06E+01
Nickel	7440-02-0	0.39	9.55E-04	7.90E+00
Phenol	108-95-2	36.8	9.02E-02	7.45E+02
Selenium	7782-49-2	0.56	1.37E-03	1.13E+01
Sulfuric acid and sulfates	7664-93-9	572	1.40E+00	1.16E+04
Toluene	108-88-3	0.033	8.08E-05	6.68E-01

Notes:

Under a mature operating scenario, the unit will primarily fire syngas.

1) HRSG (firing syngas) operating hours = 8,322 hour per year
2) Hourly emissions based on 100 percent load at winter minimum temperature (20°F)
3) Annual emissions based on 100 percent load at annual average temperature (65°F)
4) Emission rates 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.
5) 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

Btu = British thermal units

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Cooling Tower Operating Parameters

	Power Block	Process Area	ASU
Cooling water (CW) circulation rate, gpm =	175,000	42,300	40,200
CW circulation rate (million lb/hr) =	88	21	20
CW dissolved solids (ppmw) =	9,000	9,000	9,000
Drift, fraction of circulating CW =	0.0005%	0.0005%	0.0005%

Note: Assumed 9,000 ppm TDS in circulating cooling water. Circulating water could range from 1,200 to 90,000 ppm TDS depending on makeup water quality and tower operation. PM_{10} emissions would vary proportionately.

Cooling Tower Operating Hours = 8,322.0 hours per year

Power Block

Compound	CAS #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	0.026	1.13E-05	9.38E-02
Copper	7440-50-8	0.005	2.19E-06	1.82E-02
Fluoride		0.45	1.97E-04	1.64E+00
Manganese	7439-96-5	1.29	5.63E-04	4.68E+00
Selenium	7784-49-2	0.02	9.36E-06	7.79E-02

Notes:
1) Power block operating hours = 8,322 hours per year
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)
5) Selenium ppm value shown taken as average of analytical test results (DWR)
7) Zinc ppm value shown is one-half of stated detection limit and is no longer in OEHHA list of TAC

Gasifier Process Area

Compound	CAS #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	0.026	2.72E-06	2.27E-02
Copper	7440-50-8	0.005	5.29E-07	4.40E-03
Fluoride		0.45	4.76E-05	3.96E-01
Manganese	7439-96-5	1.29	1.36E-04	1.13E+00
Selenium	7784-49-2	0.02	2.26E-06	1.88E-02

Notes:
1) Process area operating hours = 8,322 hours per year
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)
5) Selenium ppm value shown taken as average of analytical test results (DWR)
7) Zinc ppm value shown is one-half of stated detection limit and is no longer in OEHHA list of TAC

ASU

Compound	CAS #	Emission Factor (ppm)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	0.026	2.59E-06	2.15E-02
Copper	7440-50-8	0.005	5.03E-07	4.18E-03
Fluoride		0.45	4.52E-05	3.76E-01
Manganese	7439-96-5	1.29	1.29E-04	1.08E+00
Selenium	7784-49-2	0.02	2.15E-06	1.79E-02

Notes:
1) ASU operating hours = 8,322 hours per year
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)
5) Selenium ppm value shown taken as average of analytical test results (DWR)
7) Zinc ppm value shown is one-half of stated detection limit and is no longer in OEHHA list of TAC

Hydrogen Energy California LLC *6/18/2010*
HECA Project

Operating Parameters

Gasifier Heat Input =	18	10^6 Btu/hr (HHV)
Reference HHV =	1,050	Btu/scf
=	0.017	10^6 scf/hr
Gasifier Heater Operating Hours per Heater =	1,200	hours per year
Number of Heaters =	3	

Compound	CAS #	Emission Factor (lb/10^6 scf)	Hourly Per Heater (lb/hr)	Annual Per Heater (lb/yr)	Annual All 3 Heaters (lb/yr)
Arsenic	7440-38-2	2.00E-04	6.86E-06	4.11E-03	1.23E-02
Benzene	71-43-2	2.10E-03	7.20E-05	4.32E-02	1.30E-01
Beryllium	7440-41-7	1.20E-05	4.11E-07	2.47E-04	7.41E-04
Cadmium	7440-43-9	1.10E-03	3.77E-05	2.26E-02	6.79E-02
Chromium	7440-47-3	1.40E-03	4.80E-05	2.88E-02	8.64E-02
Cobalt	7440-48-4	8.40E-05	2.88E-06	1.73E-03	5.18E-03
Copper	7440-50-8	8.50E-04	2.91E-05	1.75E-02	5.25E-02
Formaldehyde	50-00-0	7.50E-02	2.57E-03	1.54E+00	4.63E+00
Hexane	110-54-3	1.80E+00	6.17E-02	3.70E+01	1.11E+02
Manganese	7439-96-5	3.80E-04	1.30E-05	7.82E-03	2.35E-02
Mercury	7439-97-6	2.60E-04	8.91E-06	5.35E-03	1.60E-02
Naphthalene	91-20-3	6.10E-04	2.09E-05	1.25E-02	3.76E-02
Nickel	7440-02-0	2.10E-03	7.20E-05	4.32E-02	1.30E-01
Selenium	7782-49-2	2.40E-05	8.23E-07	4.94E-04	1.48E-03
Toluene	108-88-3	3.40E-03	1.17E-04	6.99E-02	2.10E-01
Vanadium	7440-62-2	2.30E-03	7.89E-05	4.73E-02	1.42E-01
Benzo(a)pyrene	PAH	1.20E-06	4.11E-08	2.47E-05	7.41E-05
Benz(a)anthracene	PAH	1.80E-06	6.17E-08	3.70E-05	1.11E-04
Benzo(b)fluoranthene	PAH	1.80E-06	6.17E-08	3.70E-05	1.11E-04
Chrysene	PAH	1.80E-06	6.17E-08	3.70E-05	1.11E-04
Dibenzo(a,h)anthracene	PAH	1.20E-06	4.11E-08	2.47E-05	7.41E-05
Indeno(1,2,3-cd)pyrene	PAH	1.80E-06	6.17E-08	3.70E-05	1.11E-04
2-Methylnaphthalene	PAH	2.40E-05	8.23E-07	4.94E-04	1.48E-03
3-Methylchloranthrene	PAH	1.80E-06	6.17E-08	3.70E-05	1.11E-04
7,12-Dimethylbenz(a)anthracene	PAH	1.60E-05	5.49E-07	3.29E-04	9.87E-04
Acenaphthene	PAH	1.80E-06	6.17E-08	3.70E-05	1.11E-04
Acenaphthylene	PAH	1.80E-06	6.17E-08	3.70E-05	1.11E-04
Anthracene	PAH	2.40E-06	8.23E-08	4.94E-05	1.48E-04
Benzo(g,h,i)perylene	PAH	1.20E-06	4.11E-08	2.47E-05	7.41E-05
Benzo(k)fluoranthene	PAH	1.80E-06	6.17E-08	3.70E-05	1.11E-04
Fluoranthene	PAH	3.00E-06	1.03E-07	6.17E-05	1.85E-04
Fluorene	PAH	2.80E-06	9.60E-08	5.76E-05	1.73E-04
Phenanathrene	PAH	1.70E-05	5.83E-07	3.50E-04	1.05E-03
Pyrene	PAH	5.00E-06	1.71E-07	1.03E-04	3.09E-04

Notes:

1) Gasifier operating hours = 1,200 hours per year per heater
2) Emission factor source is USEPA AP-42 Section 1.4
3) Calculation assumes fuel heating value, British thermal units/standard cubic foot, higher heating value 1,050
4) Please note that there are three gasifier heaters; however, it is assumption is that up to two gasifier heaters may operate at any one time on an as-needed basis to pre-heat the gasifier.

Auxiliary Boiler **HAP Emissions Summary**

Hydrogen Energy California LLC *6/18/2010*
HECA Project

Operating Parameters

Auxiliary Boiler Heat Input =	142	10^6 Btu/hr (HHV)
=	1050	Btu/scf
=	0.135	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	2.31E+00	3.12E-01	6.84E+02
Arsenic	7440-38-2	2.00E-04	2.70E-05	5.92E-02
Benzene	71-43-2	2.10E-03	2.84E-04	6.22E-01
Beryllium	7440-41-7	1.20E-05	1.62E-06	3.55E-03
Cadmium	7440-43-9	1.10E-03	1.49E-04	3.26E-01
Chromium	7440-47-3	1.40E-03	1.89E-04	4.15E-01
Cobalt	7440-48-4	8.40E-05	1.14E-05	2.49E-02
Copper	7440-50-8	8.50E-04	1.15E-04	2.52E-01
Formaldehyde	50-00-0	7.50E-02	1.01E-02	2.22E+01
Hexane	110-54-3	1.80E+00	2.43E-01	5.33E+02
Manganese	7439-96-5	3.80E-04	5.14E-05	1.13E-01
Mercury	7439-97-6	2.60E-04	3.52E-05	7.70E-02
Naphthalene	91-20-3	6.10E-04	8.25E-05	1.81E-01
Nickel	7440-02-0	2.10E-03	2.84E-04	6.22E-01
Selenium	7782-49-2	2.40E-05	3.25E-06	7.11E-03
Toluene	108-88-3	3.40E-03	4.60E-04	1.01E+00
Vanadium	7440-62-2	2.30E-03	3.11E-04	6.81E-01
Benzo(a)pyrene	PAH	1.20E-06	1.62E-07	3.55E-04
Benz(a)anthracene	PAH	1.80E-06	2.43E-07	5.33E-04
Benzo(b)fluoranthene	PAH	1.80E-06	2.43E-07	5.33E-04
Chrysene	PAH	1.80E-06	2.43E-07	5.33E-04
Dibenzo(a,h)anthracene	PAH	1.20E-06	1.62E-07	3.55E-04
Indeno(1,2,3-cd)pyrene	PAH	1.80E-06	2.43E-07	5.33E-04
2-Methylnaphthalene	PAH	2.40E-05	3.25E-06	7.11E-03
3-Methylchloranthrene	PAH	1.80E-06	2.43E-07	5.33E-04
7,12-Dimethylbenz(a)anthracene	PAH	1.60E-05	2.16E-06	4.74E-03
Acenaphthene	PAH	1.80E-06	2.43E-07	5.33E-04
Acenaphthylene	PAH	1.80E-06	2.43E-07	5.33E-04
Anthracene	PAH	2.40E-06	3.25E-07	7.11E-04
Benzo(g,h,i)perylene	PAH	1.20E-06	1.62E-07	3.55E-04
Benzo(k)fluoranthene	PAH	1.80E-06	2.43E-07	5.33E-04
Fluoranthene	PAH	3.00E-06	4.06E-07	8.89E-04
Fluorene	PAH	2.80E-06	3.79E-07	8.29E-04
Phenanathrene	PAH	1.70E-05	2.30E-06	5.03E-03
Pyrene	PAH	5.00E-06	6.76E-07	1.48E-03

Notes:

1) Auxiliary boiler operating hours = 2,190 hours per year
2) Emission factor source is EPA AP-42 Section 1.4
3) Calculation assumes fuel heating value,British thermal units/standard cubic foot, higher heating value 1,050

Gasification Flare — HAP Emissions Summary

Hydrogen Energy California LLC *6/18/2010*
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
Ground Flare Pilot Fuel Use = 0.5 10^6 Btu/hr

Gasification Flare - Operating Emissions During Gasifier Startup and Shutdown

Total Flare SU/SD Operation = 115,500 10^6 Btu/yr
Wet Unshifted Gas-Firing Rate = 900 10^6 Btu/hr - conservatively assuming maximum possible rate
Dry Shifted Gas-Firing Rate = 770 10^6 Btu/hr - conservatively assuming maximum possible rate

Startup and shutdown flared gas scenario

Cold plant startup =	30,000	10^6 Btu/yr (1 event)	(assume 20 percent unshifted)
Plant shutdown =	500	10^6 Btu/yr (1 event)	(assume 100 percent unshifted)
Gasifier outages =	60,000	10^6 Btu/yr (24 events)	(assume 100 percent unshifted)
Gasifier hot restarts =	25,000	10^6 Btu/yr (12 events)	(assume 100 percent unshifted)
Total	115,500	10^6 Btu/yr	(approx 75 percent unshifted)

Gasification Flare - Operating Emissions During Offline CTG Wash

Total Flare CTG Wash Operation = 81,400 10^6 Btu/yr
H2 rich during CTG Wash = 1,695 10^6 Btu/hr - conservatively assuming maximum possible rate

CTG Wash flared gas scenario

Offline CTG Wash = 81,400 10^6 Btu/yr (12 event) (assume 100% percent shifted)

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Emission ($lb/10^6$ Btu)	Hourly (lb/hr)	Annual (lb/yr)
Acetaldehyde	75-07-0	0.043	4.10E-05	6.94E-02	8.24E+00
Acrolein	107-02-8	0.01	9.52E-06	1.61E-02	1.92E+00
Benzene	71-43-2	0.159	1.51E-04	2.57E-01	3.05E+01
Ethyl Benzene	100-41-4	1.444	1.38E-03	2.33E+00	2.77E+02
Formaldehyde	50-00-0	1.169	1.11E-03	1.89E+00	2.24E+02
Naphthalene	91-20-3	0.011	1.05E-05	1.78E-02	2.11E+00
n-Hexane	110-54-3	0.029	2.76E-05	4.68E-02	5.56E+00
PAH (excluding Naphthalene)	PAH	0.003	2.86E-06	4.84E-03	5.75E-01
Propylene	115-07-1	2.44	2.32E-03	3.94E+00	4.68E+02
Toluene	108-88-3	0.058	5.52E-05	9.37E-02	1.11E+01
Xylene(s)	1330-20-7	0.029	2.76E-05	4.68E-02	5.56E+00
Arsenic	7440-38-2	2.00E-04	1.90E-07	3.23E-04	3.83E-02
Beryllium	7440-41-7	1.20E-05	1.14E-08	1.94E-05	2.30E-03
Cadmium	7440-43-9	1.10E-03	1.05E-06	1.78E-03	2.11E-01
Chromium	7440-47-3	1.40E-03	1.33E-06	2.26E-03	2.68E-01
Cobalt	7440-48-4	8.40E-05	8.00E-08	1.36E-04	1.61E-02
Copper	7440-50-8	8.50E-04	8.10E-07	1.37E-03	1.63E-01
Lead	7439-92-1	5.00E-04	4.76E-07	8.07E-04	9.58E-02
Manganese	7439-96-5	3.80E-04	3.62E-07	6.14E-04	7.28E-02
Mercury	7439-97-6	2.60E-04	2.48E-07	4.20E-04	4.98E-02
Nickel	7440-02-0	2.10E-03	2.00E-06	3.39E-03	4.03E-01
Selenium	7782-49-2	2.40E-05	2.29E-08	3.88E-05	4.60E-03
Vanadium	7440-62-2	2.30E-03	2.19E-06	3.71E-03	4.41E-01

Notes:

1) Annual operation assumes total pilot operation of 8,760 hr/yr and 115,500 10^6 Btu/yr during gasifier startup and shutdown, plus 81,400 10^6 Btu/yr for CTG washes.

2) Emission factors based on AP-42 Chpt. 1.4 (for metals) and VCAPCD AB2588 (for non-metals).

3) Calculation assumes fuel heating value, Btu/scf, higher heating value 1,050

Hydrogen Energy California LLC
HECA Project

6/18/2010

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)
Acetaldehyde	75-07-0	0.043	4.10E-05	1.49E-03	1.67E-01
Acrolein	107-02-8	0.01	9.52E-06	3.46E-04	3.87E-02
Benzene	71-43-2	0.159	1.51E-04	5.50E-03	6.16E-01
Ethyl Benzene	100-41-4	1.444	1.38E-03	4.99E-02	5.59E+00
Formaldehyde	50-00-0	1.169	1.11E-03	4.04E-02	4.53E+00
Naphthalene	91-20-3	0.011	1.05E-05	3.80E-04	4.26E-02
n-Hexane	110-54-3	0.029	2.76E-05	1.00E-03	1.12E-01
PAH (excluding Naphthalene)	PAH	0.003	2.86E-06	1.04E-04	1.16E-02
Propylene	115-07-1	2.44	2.32E-03	8.44E-02	9.45E+00
Toluene	108-88-3	0.058	5.52E-05	2.01E-03	2.25E-01
Xylene(s)	1330-20-7	0.029	2.76E-05	1.00E-03	1.12E-01
Arsenic	7440-38-2	2.00E-04	1.90E-07	6.91E-06	7.75E-04
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
Lead	7439-92-1	5.00E-04	4.76E-07	1.73E-05	1.94E-03
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
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
Vanadium	7440-62-2	2.30E-03	2.19E-06	7.95E-05	8.91E-03

Notes:

1) Annual operation assumes total pilot operation of 8,760 hr/yr and 6 hr/yr during gasifier startup and shutdown with assist gas.
2) Emission factors based on AP-42 Chpt. 1.4 (for metals) and VCAPCD AB2588 (for non-metals).
3) Calculation assumes fuel heating value, Btu/scf, higher heating value 1,050

Hydrogen Energy California LLC *6/18/2010*
HECA Project

Operating Parameters - Normal Operating Emissions From Pilot

Rectisol Flare Pilot Firing Rate = 0.3 MMBtu/hr
Annual Operating Hours = 8,760 hr/yr

Compound	CAS Number	Emission Factor ($lb/10^6$ scf)	Emission Factor (lb/MMBtu)	Hourly (lb/hr)	Annual (lb/yr)
2-Methylnaphthalene	91576	2.40E-05	2.35E-08	7.06E-09	6.18E-05
3-Methylchloranthrene	56495	1.80E-06	1.76E-09	5.29E-10	4.64E-06
7,12-Dimethylbenz(a)anthracene	57976	1.60E-05	1.57E-08	4.71E-09	4.12E-05
Acenaphthene	83329	1.80E-06	1.76E-09	5.29E-10	4.64E-06
Acenaphthylene	208968	1.80E-06	1.76E-09	5.29E-10	4.64E-06
Anthracene	120127	2.40E-06	2.35E-09	7.06E-10	6.18E-06
Benz(a)anthracene	56553	1.80E-06	1.76E-09	5.29E-10	4.64E-06
Benzene	71432	2.10E-03	2.06E-06	6.18E-07	5.41E-03
Benzo(a)pyrene	50328	1.20E-06	1.18E-09	3.53E-10	3.09E-06
Benzo(b)fluoranthene	205992	1.80E-06	1.76E-09	5.29E-10	4.64E-06
Benzo(g,h,i)perylene	191242	1.20E-06	1.18E-09	3.53E-10	3.09E-06
Benzo(k)fluoranthene	205823	1.80E-06	1.76E-09	5.29E-10	4.64E-06
Chrysene	218019	1.80E-06	1.76E-09	5.29E-10	4.64E-06
Dibenzo(a,h)anthracene	53703	1.20E-06	1.18E-09	3.53E-10	3.09E-06
Dichlorobenzene	25321226	1.20E-03	1.18E-06	3.53E-07	3.09E-03
Fluoranthene	206440	3.00E-06	2.94E-09	8.82E-10	7.73E-06
Fluorene	86737	2.80E-06	2.75E-09	8.24E-10	7.21E-06
Formaldehyde	50000	7.50E-02	7.35E-05	2.21E-05	1.93E-01
Hexane	110543	1.80E+00	1.76E-03	5.29E-04	4.64E+00
Indeno(1,2,3-cd)pyrene	193395	1.80E-06	1.76E-09	5.29E-10	4.64E-06
Naphthalene	91203	6.10E-04	5.98E-07	1.79E-07	1.57E-03
Phenanthrene	85018	1.70E-05	1.67E-08	5.00E-09	4.38E-05
Pyrene	129000	5.00E-06	4.90E-09	1.47E-09	1.29E-05
Toluene	108883	3.40E-03	3.33E-06	1.00E-06	8.76E-03
Arsenic	7440382	2.00E-04	1.96E-07	5.88E-08	5.15E-04
Barium	7440393	4.40E-03	4.31E-06	1.29E-06	1.13E-02
Beryllium	7440417	1.20E-05	1.18E-08	3.53E-09	3.09E-05
Cadmium	7440439	1.10E-03	1.08E-06	3.24E-07	2.83E-03
Chromium	7440473	1.40E-03	1.37E-06	4.12E-07	3.61E-03
Cobalt	7440484	8.40E-05	8.24E-08	2.47E-08	2.16E-04
Copper	7440508	8.50E-04	8.33E-07	2.50E-07	2.19E-03
Manganese	7439965	3.80E-04	3.73E-07	1.12E-07	9.79E-04
Mercury	7439976	2.60E-04	2.55E-07	7.65E-08	6.70E-04
Nickel	7440020	2.10E-03	2.06E-06	6.18E-07	5.41E-03
Selenium	7782492	2.40E-05	2.35E-08	7.06E-09	6.18E-05
Vanadium	7440622	2.30E-03	2.25E-06	6.76E-07	5.93E-03

Notes:

1) Emission factors ($lb/10^6$ scf) are from AP-42, Chapter 1.4, Table 1.4-3. Factors in pounds per 10E-06 scf were converted to factors in lb/MMBtu by dividing by 1,020.

Tail Gas Thermal Oxidizer — HAP Emissions Summary

Hydrogen Energy California LLC — *6/18/2010*
HECA Project

Operating Parameters

Tail Gas Thermal Oxidizer Heat Input =	10	10^6 Btu/hr (HHV)
Reference HHV =	1,050	Btu/scf
=	0.010	10^6 scf/hr
Tail Gas Thermal Oxidizer Operating Hours =	8,760	hr/yr

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Hourly (lb/hr)	Annual (lb/yr)
Arsenic	7440-38-2	2.00E-04	1.90E-06	1.67E-02
Benzene	71-43-2	2.10E-03	2.00E-05	1.75E-01
Beryllium	7440-41-7	1.20E-05	1.14E-07	1.00E-03
Cadmium	7440-43-9	1.10E-03	1.05E-05	9.18E-02
Chromium	7440-47-3	1.40E-03	1.33E-05	1.17E-01
Cobalt	7440-48-4	8.40E-05	8.00E-07	7.01E-03
Copper	7440-50-8	8.50E-04	8.10E-06	7.09E-02
Formaldehyde	50-00-0	7.50E-02	7.14E-04	6.26E+00
Hexane	110-54-3	1.80E+00	1.71E-02	1.50E+02
Manganese	7439-96-5	3.80E-04	3.62E-06	3.17E-02
Mercury	7439-97-6	2.60E-04	2.48E-06	2.17E-02
Naphthalene	91-20-3	6.10E-04	5.81E-06	5.09E-02
Nickel	7440-02-0	2.10E-03	2.00E-05	1.75E-01
Selenium	7782-49-2	2.40E-05	2.29E-07	2.00E-03
Toluene	108-88-3	3.40E-03	3.24E-05	2.84E-01
Vanadium	7440-62-2	2.30E-03	2.19E-05	1.92E-01
Benzo(a)pyrene	PAH	1.20E-06	1.14E-08	1.00E-04
Benz(a)anthracene	PAH	1.80E-06	1.71E-08	1.50E-04
Benzo(b)fluoranthene	PAH	1.80E-06	1.71E-08	1.50E-04
Chrysene	PAH	1.80E-06	1.71E-08	1.50E-04
Dibenzo(a,h)anthracene	PAH	1.20E-06	1.14E-08	1.00E-04
Indeno(1,2,3-cd)pyrene	PAH	1.80E-06	1.71E-08	1.50E-04
2-Methylnaphthalene	PAH	2.40E-05	2.29E-07	2.00E-03
3-Methylchloranthrene	PAH	1.80E-06	1.71E-08	1.50E-04
7,12-Dimethylbenz(a)anthracene	PAH	1.60E-05	1.52E-07	1.33E-03
Acenaphthene	PAH	1.80E-06	1.71E-08	1.50E-04
Acenaphthylene	PAH	1.80E-06	1.71E-08	1.50E-04
Anthracene	PAH	2.40E-06	2.29E-08	2.00E-04
Benzo(g,h,i)perylene	PAH	1.20E-06	1.14E-08	1.00E-04
Benzo(k)fluoranthene	PAH	1.80E-06	1.71E-08	1.50E-04
Fluoranthene	PAH	3.00E-06	2.86E-08	2.50E-04
Fluorene	PAH	2.80E-06	2.67E-08	2.34E-04
Phenanathrene	PAH	1.70E-05	1.62E-07	1.42E-03
Pyrene	PAH	5.00E-06	4.76E-08	4.17E-04

Notes:

1) Tail gas thermal oxidizer operating hours = 8,760 (accounting for both process vent and SRU startup)
2) Emission factor source is USEPA AP-42 Section 1.4
3) Calculation assumes fuel heating value, Btu/scf, HHV 1,050

Hydrogen Energy California LLC *6/18/2010*
HECA Project

Operating Parameters

Total Days of Operation =	21	day/yr
Total Hours of Operation =	504	hr/yr
Total Flow =	656,000	lb/hr
Total Flow =	15,150	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	43	3.91E+01	1.97E+04
Hydrogen Sulfide	7783-06-4	10	5.15E+00	2.60E+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 — *6/18/2010*
HECA Project

Operating Parameters

Emergency Generator Specification = 2,800 Bhp
Emergency Generator Operating Hours = 52 hr/yr

Compound	CAS #	Emission Factor (g/Bhp/hr)	Hourly Each Generator (lb/hr)	Annual Each Generator (lb/yr)	Annual Both Generators (lb/yr)
Diesel Particulate Matter	DPM	0.07	4.60E-01	2.39E+01	4.79E+01

Note:
1) Emergency generator operating hours = 52 hours per year per generator
2) Emission factor based on Tier 4 EPA IC Non-road Engines

Emergency Diesel Firewater Pump — HAP Emissions Summary

Hydrogen Energy California LLC *6/18/2010*
HECA Project

Operating Parameters

Fire Water Pump Specification = 556 Bhp
Fire Water Pump Operating Hours = 100 hr/yr

Compound	CAS #	Emission Factor (g/Bhp/hr)	Hourly (lb/hr)	Annual (lb/yr)
Diesel Particulate Matter	DPM	0.015	1.84E-02	1.84E+00

Note:
1) Fire water pump operating hours = 100 hours per year
2) Emission factor based on Tier 4 EPA IC Non-road Engines

Summary of On Site Operations Truck DPM Emissions - HECA — Emissions Summary

Hydrogen Energy California LLC
HECA Project

6/18/2010

Transportation Information

		Notes
- Onsite Vehicle =	10 diesel trucks	- Information Provided By Applicant
- Scenario year=	2040	- Assumed based on 70-yr risk calculation period
- 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 (@ 15 mph)
Mileage	
1-hr	1
Annual average trucks or loads	10000

EMFAC2007 Emission Factor	Diesel LHDT2
PM10 * (g/mi)	0.03

HARP input assumed 2040 scenario (70 years average)
HARP PM_{10} emission factor does not include tire wear or break wear contributions

	g/s		
max hourly PM10 emission rate per truck	9.8E-06	7.8E-05	lb/hr
annual PM10 emission rate per truck	9.8E-06	0.68	lb/yr

Annual Emission Rates for HARP per 10 Diesel Trucks (lb/yr): 6.83
Annual Emission Rates for HARP per 10 Diesel Trucks (tpy): 0.0034

Hydrogen Energy California LLC *6/18/2010*
HECA Project

Data Supplied By Client				
Parameter	Coke and Coal Trucks (@ 10 mph)		Onsite Gasifier Solids Handling (@ 5 mph)	
	Running Emissions	Idling Emissions	Running Emissions	Idling Emissions
Distance Traveled (mi)	1.00		0.500	
Per Truck Idle Time (hr)		0.117		0.083
No. Volume Sources for Modeling	85	1	50	2
Maximum number of trucks or loads				
1-hr	18	18	2	2
Annual average	35,500	35500	2,900	2900
EMFAC2007 Emission Factors (g/mi or g/idle-hour)				
PM10	0.08	0.122	0.09	0.122

HARP input assumed 2040 scenario (70 years average). Emission rate does not include tire/brake wear.

PM10 Emission Rates

	Coke and Coal Trucks (@ 10 mph)		Onsite Gasifier Solids Handling (@ 5 mph)	
Emission Rates for HARP	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle
1-hr PM10 (lb/hr)	3.3E-03	5.6E-04	2.0E-04	4.5E-05
Annual PM10 (lb/yr)	6.4E+00	1.1E+00	2.9E-01	6.5E-02

HARP Inputs - Annual and Hourly Emission Rates per Volume Source

	Coke and Coal Trucks (@ 10 mph)		Onsite Gasifier Solids Handling (@ 5 mph)	
	Running Emissions	Idling Emissions (at each Idle Point)	Running Emissions	Idling Emissions (at each Idle
Max PM10 lb/hr/volume source	3.83E-05	5.65E-04	3.97E-06	2.24E-05
PM10 lb/yr/volume source	7.55E-02	1.11E+00	5.75E-03	3.25E-02

Title : SJVAB LHDT2 and HHD Trucks 2040 for HARP
Version : Emfac2007 V2.3 Nov 1 2006
Run Date : 2010/05/07 09:02:10
Scen Year: 2040 -- All model years in the range 1996 to 2040 selected
Season : Annual
Area : San Joaquin Valley
****

Year: 2040 -- Model Years 1996 to 2040 Inclusive -- Annual
Emfac2007 Emission Factors: V2.3 Nov 1 2006

San Joaquin Valley Basin Average Basin Average

Table 1: Running Exhaust Emissions (grams/mile; grams/idle-hour)

Pollutant Name: PM10 Temperature: 70F Relative Humidity: 30%

Speed MPH	LHD2 CAT	LHD2 DSL	LHD2 ALL	HHD CAT	HHD DSL	HHD ALL
0	0	0.8	0.337	0	0.122	0.12
5	0.044	0.049	0.046	0.092	0.09	0.09
10	0.029	0.039	0.033	0.06	0.082	0.082
15		0.031				

Hydrogen Energy California LLC
HECA Project
6/18/2010

Summary: Total Controlled Emissions

Compound	Emissions (lb/hr)	Emissions (tpy)
CO_2	9.07	39.72
CO	1.36	5.95
CH_4	5.17E-03	2.26E-02
H_2S	0.55	2.42
COS	1.10E-02	0.05
CH_3OH	1.62	7.09
C_3H_6	1.44	6.33
NH_3	0.04	0.17
HCN	1.15E-03	5.06E-03
MDEA	1.42	6.24
Total VOC	**4.50**	**19.70**

Summary by Volume Source - Emissions are divided by number of Volume Sources

"POWER" Two Volume Sources (Area # 10)

	lb/hr	lb/yr
H_2S	0.01	73.44
CH_3OH		
C_3H_6		
NH_3	0.01	90.35
HCN	6.54E-05	0.57

"SRU" Three Volume Sources (Area # 9, #11)

	lb/hr	lb/yr
H_2S	0.04	352.80
CH_3OH	3.48E-05	0.30
C_3H_6		
NH_3		
HCN		

"SWS" Three Volume Sources (Area #6)

	lb/hr	lb/yr
H_2S	3.80E-03	33.30
CH_3OH		
C_3H_6		
NH_3	0.02	137.12
HCN		

"TGTU" Three Volume Sources (Areas #1, #7, #8, #12, #13)

	lb/hr	lb/yr
H_2S	0.02	191.83
CH_3OH	0.54	4,723.96
C_3H_6		
NH_3		
HCN		

"AGR" Three Volume Sources (Area # 5)

	lb/hr	lb/yr
H_2S		
CH_3OH		
C_3H_6	0.48	4,219.33
NH_3		
HCN		

"GASIFICATION" Five Volume Sources (Areas #2, #3)

	lb/hr	lb/yr
H_2S	0.04	390.79
CH_3OH		
C_3H_6		
NH_3	4.13E-04	3.62
HCN	2.05E-04	1.79

"SHIFT" Two Volume Sources (Area # 4)

	lb/hr	lb/yr
H_2S	0.06	506.85
CH_3OH		
C_3H_6		
NH_3		
HCN		

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

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.
(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)

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	0.68	3.00
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	0.72	3.16
			Total	**1.41**	**6.16**
			CO_2	0.47	2.08
			CO	0.87	3.83
			CH_4	1.09E-03	4.79E-03
			H_2S	0.05	0.22
			COS	4.11E-03	0.02
			NH_3	1.81E-03	0.01
			HCN	9.76E-05	4.28E-04

Area #3: Flash Gas - Gasification

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	Uncontrolled Emissions (E_{TOC}) tpy
Valves	Gas	49	8760	0.57	2.50
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	0.44	1.95
Connectors	All	151	8760	0.54	2.36
			Total	**1.55**	**6.80**
			CO_2	0.98	4.30
			CO	0.39	1.72
			CH_4	5.50E-04	2.41E-03
			H_2S	0.17	0.76
			COS	4.12E-03	0.02
			NH_3	2.59E-04	1.14E-03
			HCN	9.26E-04	4.06E-03

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	2.45	10.73
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	0.47	2.07
Connectors	All	632	8760	2.40	10.50
			Total	**5.32**	**23.30**
			CO_2	5.12	22.41
			CO	0.08	0.37
			CH_4	3.48E-03	0.02
			H_2S	0.12	0.51
			COS	3.25E-04	1.43E-03

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

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
			CO	3.47E-03	0.02	3.21E-04	1.41E-03
			CH_4	2.94E-04	1.29E-03	2.72E-05	1.19E-04
			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
			CO	1.37E-03	0.01	1.12E-04	4.90E-04
			CH_4	1.17E-04	5.11E-04	9.55E-06	4.18E-05
			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
			CO	2.65E-03	0.01	1.99E-04	8.72E-04
			CH_4	7.19E-05	3.15E-04	5.40E-06	2.37E-05
			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
			CO	0.01	0.06	1.02E-03	4.47E-03
			CH_4	7.67E-05	3.36E-04	5.79E-06	2.54E-05
			H_2S	0.22	0.97	0.02	0.07
			COS	8.03E-04	3.52E-03	6.07E-05	2.66E-04
			NH_3	0.27	1.20	0.02	0.09
			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	68	8760	1.02E-05	4.48E-05
Pump Seals	Light Liquid	0	8760	-	-
Pump Seals	Heavy Liquid	4	8760	2.25E-05	9.87E-05
Compressor Seals	Gas	0	8760	-	-
Connectors	All	297	8760	3.55E-04	1.56E-03
			Total	**3.88E-04**	**1.70E-03**
			H_2S	3.88E-04	1.70E-03

Area #12: TGTU Process Gas

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	tpy
Valves	Gas	72	8760	0.63	2.77
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	290	8760	0.78	3.43
			Total	**1.42**	**6.20**
			CO_2	1.37	6.00
			CO	0.01	0.03
			H_2S	0.04	0.17
			COS	7.28E-04	3.19E-03

Area #13: TGTU Amine

Component	Service	Equipment Count (N)	Annual Hours of Operation	Uncontrolled Emissions (E_{TOC}) lb/hr	tpy
Valves	Gas	0	8760	-	-
Valves	Light Liquid	0	8760	-	-
Valves	Heavy Liquid	264	8760	0.06	0.27
Pump Seals	Light Liquid	0	8760	-	-
Pump Seals	Heavy Liquid	5	8760	0.04	0.19
Compressor Seals	Gas	0	8760	-	-
Connectors	All	746	8760	1.39	6.10
			Total	**1.50**	**6.56**
			CO_2	0.06	0.28
			H_2S	0.01	0.04
			MDEA	1.42	6.24

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.

Area Speciation

Comound	Wt % (WF_{TOC})												
	Methanol	Syn Gas	Flash Gas - Gasification	Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	TGTU Process Gas	TGTU Amine
CO_2	0.00%			90.43%	0.00%	2.50%	44.68%	35.81%	60.32%	68.32%	0.00%	64.65%	1.98%
CO	0.00%			1.48%	0.00%	0.001%	0.03%	0.04%	0.06%	0.36%	0.00%	0.31%	0.00%
CH_4	0.00%			0.06%	0.00%	0.00%	0.003%	0.003%	0.002%	0.002%	0.00%	0.00%	0.00%
H_2S	0.00%			2.05%	0.00%	0.18%	1.73%	0.0001%	39.04%	5.98%	0.03%	1.86%	0.32%
COS	0.00%			0.01%	0.00%	0.00%	0.01%	0.00%	0.51%	0.02%	0.00%	0.03%	0.00%
CH_3OH	100.00%			0.00%	0.00%	0.00%	53.51%	64.10%	0.03%	0.00%	0.00%	0.00%	0.00%
C_3H_6	0.00%			0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NH_3	0.00%			0.00%	0.00%	0.25%	0.00%	0.00%	0.00%	7.36%	0.00%	0.00%	0.00%
HCN	0.00%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.05%	0.00%	0.00%	0.00%
MDEA	0.00%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	43.96%
WF_{TOC} [1]	**100.00%**			**94.03%**	**100.00%**	**2.93%**	**99.96%**	**99.95%**	**99.98%**	**82.10%**	**0.03%**	**66.85%**	**46.25%**

Conversion Note:
1 kg = 2.20 pound

Note:
(1) WF_{TOC} 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	3	4	5	6	7	8	9	10	11	12	13
	Methanol	Syn Gas	Flash Gas - Gasification	Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	TGTU Process Gas	TGTU Amine
Valves - Gas	50	108	49	198	188	0	94	79	161	157	0	72	0
Valves - Light Liquid	416	0	0	0	288	0	358	79	0	0	0	0	0
Valves - Heavy Liquid	0	0	0	0	0	508	0	0	0	0	68	0	264
Pumps - Light Liquid	7	0	0	0	3	0	7	0	0	0	0	0	0
Pumps - Heavy Liquid	0	0	0	0	0	17	0	0	0	0	4	0	5
Compressors	0	0	1	1	1	0	0	0	0	0	0	0	0
Connectors	1225	372	151	632	1432	1410	1323	516	492	407	297	290	746
	1698	**480**	**201**	**831**	**1912**	**1935**	**1782**	**674**	**653**	**564**	**369**	**362**	**1015**

	Process Area													
	1	2	3	4	5	6	7	8	9	10	11	12	13	
	Methanol	Syn Gas	Flash Gas - Gasification	Shifted Syn Gas	Propylene	Sour Water	H_2S Laden Methanol	CO_2 Laden Methanol	Acid Gas	Ammonia-Laden Gas	Sulfur	TGTU Process Gas	TGTU Amine	Total
Compound	**Annual Fugitive Emissions with LDAR Application (ton/yr)**													
CO_2				22.41		0.69	1.82	0.49	0.81	0.84		6.00	0.28	39.72
CO				0.37		0.00	0.00	0.00	0.00	0.00		0.03		5.95
CH_4				0.02			0.00	0.00	0.00	0.00				0.02
H_2S				0.51		0.05	0.07	0.00	0.53	0.07	0.00	0.17	0.04	2.42
COS				0.00			0.00		0.01	0.00		0.00		0.05
CH_3OH	4.02						2.18	0.88	0.00					7.09
C_3H_6					6.33									6.33
NH_3						0.07				0.09				0.17
HCN										0.00				0.01
MDEA													6.24	6.24
Total VOC	**4.02**	**0.02**	**0.02**	**0.00**	**6.33**	**0.00**	**2.18**	**0.88**	**0.01**	**0.00**	**0.00**	**0.00**	**6.24**	**19.70**
Total percentage of VOC content of gas in each process area	100.00%	0.14%	0.29%	0.01%	100.00%	0.00%	53.51%	64.10%	0.54%	0.07%	0.00%	0.03%	43.96%	

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, HCN, and MDEA

APPENDIX D
CALMET/CALPUFF Air Quality Modeling Results

REVISED CALMET/CALPUFF Air Quality Modeling Impact Analysis for Far-Field Class I Areas

FOR THE

HYDROGEN ENERGY CALIFORNIA (HECA) PROJECT

Kern County, CA

Prepared for:

U.S. Forest Service
U.S. Environmental Protection Agency Region IX

Prepared by:

URS
1615 Murray Canyon Road, Suite 1000
San Diego, CA 92108

June 2010

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1.0 BACKGROUND

In accordance with comments received from the U.S. Forest Service (USFS), National Park Service (NPS) and U.S. Environmental Protection Agency (U.S. EPA) Region 9 regarding far-field air quality modeling analysis for the proposed Hydrogen Energy California (HECA) Project, a refined CALPUFF modeling analysis was performed in conjunction with the CALMET diagnostic meteorological model. HECA submitted a CALPUFF air quality modeling impact analysis report in September 2009 to USFS, California Energy Commission (CEC) and U.S. EPA. On May 7, 2010, the USFS requested additional air dispersion modeling to address the following comments.

- Use the background ammonia concentration of 20 parts per billion (ppb), as recommended by the USFS for other projects in the San Joaquin Valley.
- Set the regulatory default switch (MREG = 1) of the CALPUFF model to force all model inputs to the U.S. EPA-approved regulatory settings.
- Correct the application of the particle speciation data. Overall, the speciation between sulfate, Secondary Organic Aerosol (SOA), and Elemental Carbon (EC) appears to be correct. However, the Applicant applied the recommended particle size information to the SOA component of the emissions, which are condensible particulate matter less than 10 microns in diameter (PM_{10}) emissions. The published particle size data should have been applied only to the filterable portion of the PM_{10} emissions, which were modeled as EC. The use of the particle size information is voluntary and is not required for CALPUFF. However, if applied, the particle size information needs to be input correctly.
- Use the correct extinction coefficient in CALPOST for particulate matter. If the Applicant can accurately define the particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) fraction for any source category, these emissions should be assigned as PMF, with an extinction coefficient of 1.0. Any remaining PM_{10}, which is larger than 2.5 microns, can be modeled as PMC, with an extinction coefficient of 0.6. If the Applicant cannot accurately define the $PM_{2.5}$ and smaller fraction for a particular source category, then all PM_{10} emissions for that source should be modeled as PMF as a conservative assumption. It is not acceptable to model PM_{10} as PMC as this assumes that zero emissions occur in the $PM_{2.5}$ fraction and results in underestimating the resulting visibility impact.
- Clearly state in the Class I modeling report what visibility calculation methods were used, i.e., Method 2. The visibility calculation method used was not clear from the Applicant's earlier data submittal. An analysis of visibility impacts using Method 2 is required. Data using other methods may be included at the Applicant's discretion.
- Include Dome Land Wilderness receptors in the modeling analysis. The 100-kilometer (km) cut-off used by the Applicant is arbitrary and excludes impacts to Class I areas just beyond 100 km that may be impacted more frequently by plant emissions. It appears that Dome Land can be included in the modeling without modifying the current modeling domain. Applicant may forgo the standard 50-km buffer around CALPUFF receptors as necessary to include the Dome Land receptors. Impacts should be listed separately for Dome Land vs. San Rafael.

Based upon a conversation with Mr. Howard Gebhart, the USFS's consultant, on May 28, 2010, and further discussion with Mr. Mike McCorision, USFS, on June 2, 2010, HECA revised the CALPUFF modeling to incorporate all of the USFS suggestions, except the inclusion of Dome Land Wilderness Area. Since the original CALMET domain does not extend far enough to cover the receptors in Dome Land Wilderness Area, it was determined that the CALMET analysis would have to be completely redone to incorporate that Class I Area. Therefore, based upon the comments from USFS, NPS and U.S. EPA, the refined CALPUFF modeling considered only San Rafael Wilderness Class I PSD area for the analysis.

1.1 Model Selection and Setup

The CALPUFF air dispersion model is the preferred model for long-range transport recommended by the Federal Land Managers' Air Quality Related Value Workgroup (FLAG) guidance and the Interagency Working Group on Air Quality Modeling (IWAQM) Phase 2 Summary Report. To estimate air quality impacts at distances greater than 50 km, the CALPUFF model was used in conjunction with the CALMET diagnostic meteorological model. CALPUFF is a puff-type model that can incorporate three-dimensionally varying wind fields, wet and dry deposition, and atmospheric gas and particle-phase chemistry.

The CALMET model is used to prepare the necessary gridded wind fields for use in the CALPUFF model. CALMET can accept as input mesoscale meteorological data (MM5 data), surface, upper air, precipitation, cloud cover, and over-water meteorological data (all in a variety of input formats). These data are merged and the effects of terrain and land cover types are estimated. This process results in the generation of gridded three-dimensional (3-D) wind field that accounts for the effects of slope flows, terrain blocking effects, flow channelization, and spatially varying land use types.

The development of model inputs and options for CALMET/CALPUFF processor was based on guidance provided in following references:

- Federal Land Managers' (FLM)'s comments received in March, May and June 2010;
- FLM's Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000);
- Inter-agency Working Group on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts (December 1998);
- CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States (August 15, 2006);
- CALPUFF Reviewer's Guide (DRAFT) prepared for the United States Department of Agriculture (USDA) Forest Service and NPS (September 2005); and
- Permit application PSD particulate matter speciation methodology developed by Don Shepherd, NPS (2009).

Key input and model options selected are discussed in the following sections.

The most recent U.S. EPA-approved version of the CALMET, CALPUFF, CALPOST system (version 5.8, version 5.8 and version 5.6394, respectively) was used.

1.2 Domain

The same CALMET/CALPUFF modeling domain used in previous analyses was used in this revised analysis. The CALMET/CALPUFF modeling domain was specified using the Lambert Conformal Conic (LCC) Projection system in order to capture the earth curvature of the large modeling domain more accurately for this Project. The false easting and northing at the projection origin were both set to zero. The latitude and longitude of the projection origin were set to 35.057 N and 119.643 W, respectively. Matching parallels of latitude 1 and 2 were defined as 34.38 N and 35.67 N, respectively. The choice of the matching parallels was made according to the latitudinal extent of the modeling domain, and therefore the parallels should be contained within the modeling domain in order to minimize distortion. An accepted rule-of-thumb is the rule of sixths which calls for one parallel to be placed 1/6th of the domain's north-south extent south of the domain's north edge, and an identical distance north of the domain's south edge (WDEQ, 2006). The modeling domain was defined using a grid-cell arrangement that is 52 cells in X (easting) direction and 54 cells in Y (northing) direction. The grid-cells are 4 kilometers wide. Therefore, the southwest corner of the gird cell (1,1) were set to -101 km and -110 km.

At least 50 km of buffer distance was set between the outermost boundary of the San Rafael Wilderness Area and the Project in order to prevent the loss of mass outside the boundary under some meteorological scenarios that might be associated with transport to the Class I area. The total CALMET/CALPUFF modeling domain is shown in Revised Figure 1. The entire MM5 data set domain is shown for information only in Figure 2.

Revised Figure 1
CALMET/CALPUFF Modeling Domain

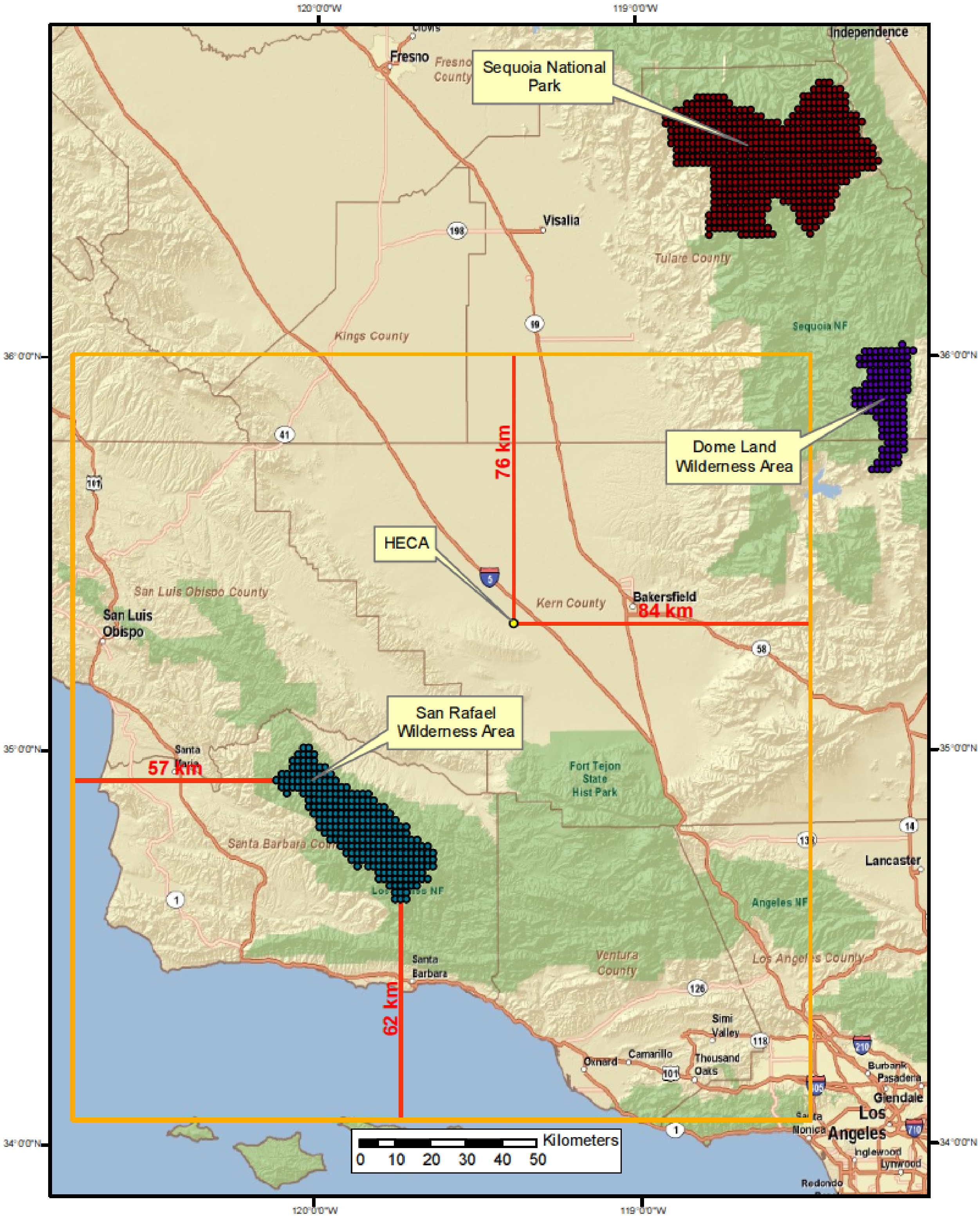


Figure 2
MM5 and CALMET/CALPUFF Modeling Domain

2.0 CALMET PROCESSING

The CALMET data and processing presented below remain the same as outlined in the previously submitted analyses.

2.1 MM5 Data

A MM5 data set was used in conjunction with the actual surface and precipitation meteorological data observations. Three years (2001-2003) of MM5 data were obtained from Western Regional Air Partnership (WRAP). This MM5 data were used for Utah and Nevada's Best Available Retrofit Technology (BART) analysis by WRAP (WRAP, 2006). The MM5 data had a 36 km resolution. Initial-guess wind fields based on hourly 36-km MM5 meteorological fields for 2001, 2002 and 2003 (IPROG =14) was used. MM5 domain is shown in Figure 2.

2.2 Hourly Surface and Precipitation Data

CALMET pre-processed hourly surface data were obtained from WRAP's CALPUFF BART website (WRAP, 2008). WRAP used approximately 190 different surface meteorological data stations for 3-year period (2001 through 2003) for BART analysis. Although thirteen stations are located within the HECA CALPUFF modeling domain, all surface stations were used for this modeling analysis.

This modeling analysis considered the effects of chemical transformations and deposition processes on ambient pollutant concentrations; therefore, observation of precipitation was included in the CALMET analysis. CALMET pre-processed precipitation data was also collected from WRAP's BART website (WRAP, 2008). The precipitation stations are co-located with surface meteorological data stations. The inverse-distance-squared interpolation scheme was used to generate a gridded precipitation field with hourly precipitation data. The radius of influence for the interpolation method was set to 100 km.

The locations of both surface and precipitation stations used in this analysis are illustrated in Figure 3.

2.3 Upper Air Data

There are three upper air stations located in the modeling domain. Point Mugu (WBAN 93111, WMO ID 72391, Lat 34.10, Long -119.12); Vandenberg (WBAN 93214, WMO ID 72393, Lat 34.75, long -120.57); and Vandenberg AFB (WBAN 93223, WMO ID 74606, Lat 34.67, Long -120.58). For Point Mugu station, no data are available for the time period of MM5 meteorological data (2001 through 2003). Vandenberg and Vandenberg AFB stations have very spotty and incomplete data. Therefore, no upper-air meteorological observations were used in the CALMET/CALPUFF modeling analysis as they are not available in the modeling domain.

In addition, Western Regional Air Partnership (WRAP) explains that the twice daily upper-air meteorological observations are used as input with the MM5 model estimates nudged to the observations as part of the Four Dimensional Data Assimilation (FDDA) in the application of the MM5. This results in higher temporal (hourly vs. 12-hour) and spatial (36 km vs. approximately 300 km) resolution upper-air meteorology in the MM5 field that is dynamically balanced than contained in the upper-air observations. Therefore, the use of the upper-air observations with

CALMET may upset the dynamic balance of the meteorological fields potentially producing spurious vertical velocities (WRAP, 2006).

2.4 CALMET ZFACE and ZIMAX Settings

Eleven vertical layers were used with vertical cell face (ZFACE) heights at 0; 20; 100; 200; 350; 500; 750; 1,000; 2,000; 3,000; 4,000; and 5,000 meters. Maximum mixing height (ZIMAX) was set to 4,500 meters based on the WRAP modeling analysis. WRAP introduced Colorado Department of Public Health and Environment (CDPHE) analyses of soundings for summer ozone events in the Denver area (CDPHE, 2005). The CDPHE analysis suggests mixing heights in the Denver area are often well above the CALMET default value of 3,000 meters during the summer. A 3,000-meter AGL maximum mixing height might be appropriate in the eastern U.S., however in the western U.S. in the summer, mixing heights may exceed this value. WRAP expected that mixing heights in excess of the 3,000-meters-above-ground-level CALMET default maximum would occur in the western States (WRAP, 2006).

2.5 Wind Field Model Options

In general, CALMET involves two steps in developing the final wind field. First, the prognostic wind field (such as MM5) is introduced into CALMET as the initial guess field. CALMET then adjusts this field by accounting for the kinematic terrain effects, slope flows, blocking effects, and 3-D divergence minimization. The wind field resulting from this step is called the Step 1 wind field. Second, CALMET further adjusts the Step 1 wind field by applying an objective analysis procedure with observational data from selected surface, upper air, and precipitation stations. This step generates the final (Step 2) wind field. The “Diagnostic Wind Module” (DWM) option follows this two-step procedure. In this analysis, the DWM option was chosen in order to reflect the terrain effects in the wind field. Because several mountain ranges occur within the modeling domain, it was expected that terrain effects would be significant.

The MM5 data were used as the initial guess wind field. The extrapolation of the surface wind data aloft (IEXTRP =-4) was used as recommended by U.S. EPA.

Wind speed and wind direction data from observation stations were only allowed to influence the Step 1 wind field at a distance determined by setting the radius-of-influence parameter. The radius of influence for the surface (RMAX1) was set to 100 km as FLM recommended. The distance from a surface observation station at which the observations and Step 1 wind field were weighted was set to 50 km, which is within the FLM’s recommended range of 20 to 80 km. Radius of influence for terrain features was set to 10 km. All of these radius-of-influence parameters were set based on CALPUFF Reviewer’s Guide (2005).

2.6 LULC and TERREL Processing

The CALMET and CALPUFF models incorporate assumptions regarding land-use classification, leaf-area index, and surface roughness length to estimate deposition during transport. These parameters were calculated with a 4-km grid spacing for the modeling domain. U.S. Geological Survey (USGS) 1:250,000 scale digital elevation models (DEMs) and Land Use Land Cover (LULC) classification files were obtained and used to develop the geophysical input files required by the CALMET model. U.S. Geological Survey (USGS) 1:250,000 scale (1-degree)

DEMs data with 90 meters resolution were obtained from the USGS ftp site: http://edcftp.cr.usgs.gov/pub/data/DEM/250/. Using nine (9) 1-degree DEM data files obtained, terrain pre-processor (TERREL) was processed to produce gridded fields of terrain elevation in the formats compatible with the CALMET. The names of 1 degree DEM quadrangles are as follows: Bakersfield-e, Bakersfield-w, Fresno-e, Fresno-w, Los_angeles-e, Log_angeles-w, Monterey-e, San_luis_obispo-e, Santa_maria-e. Figure 4 shows the elevation contours calculated within the model domain.

LULC data (*.gz) were obtained from USGS 250K site, http://edcftp.cr.usgs.gov/pub/data/LULC/. Land Use Data Preprocessors, CTGCOMP and CTGPROC were processed to compress six 250K LULC data files. After processing, the data were quality checked to ensure land use was accurately represented. USGS land use data contains 38 land use categories. These were mapped to 14 categories read by CALMET. The names of 250K LULC quadrangles are as follows: Bakersfield, Fresno, Los_Angeles, Monterey, San_luis_obispo, and Santa_maria. Figure 5 shows the plot of land use data.

The outputs of TERREL and CTGPROC were combined in the geo-physical preprocessor (MAKEGEO) to prepare the CALMET geo-physical input file. These inputs include land use type, elevation, surface parameters (surface roughness, length, albedo, bowen ratio, soil heat flux parameter, and vegetation leaf area index) and anthropogenic heat flux.

Figure 3
Locations of Surface and Precipitation Data Stations

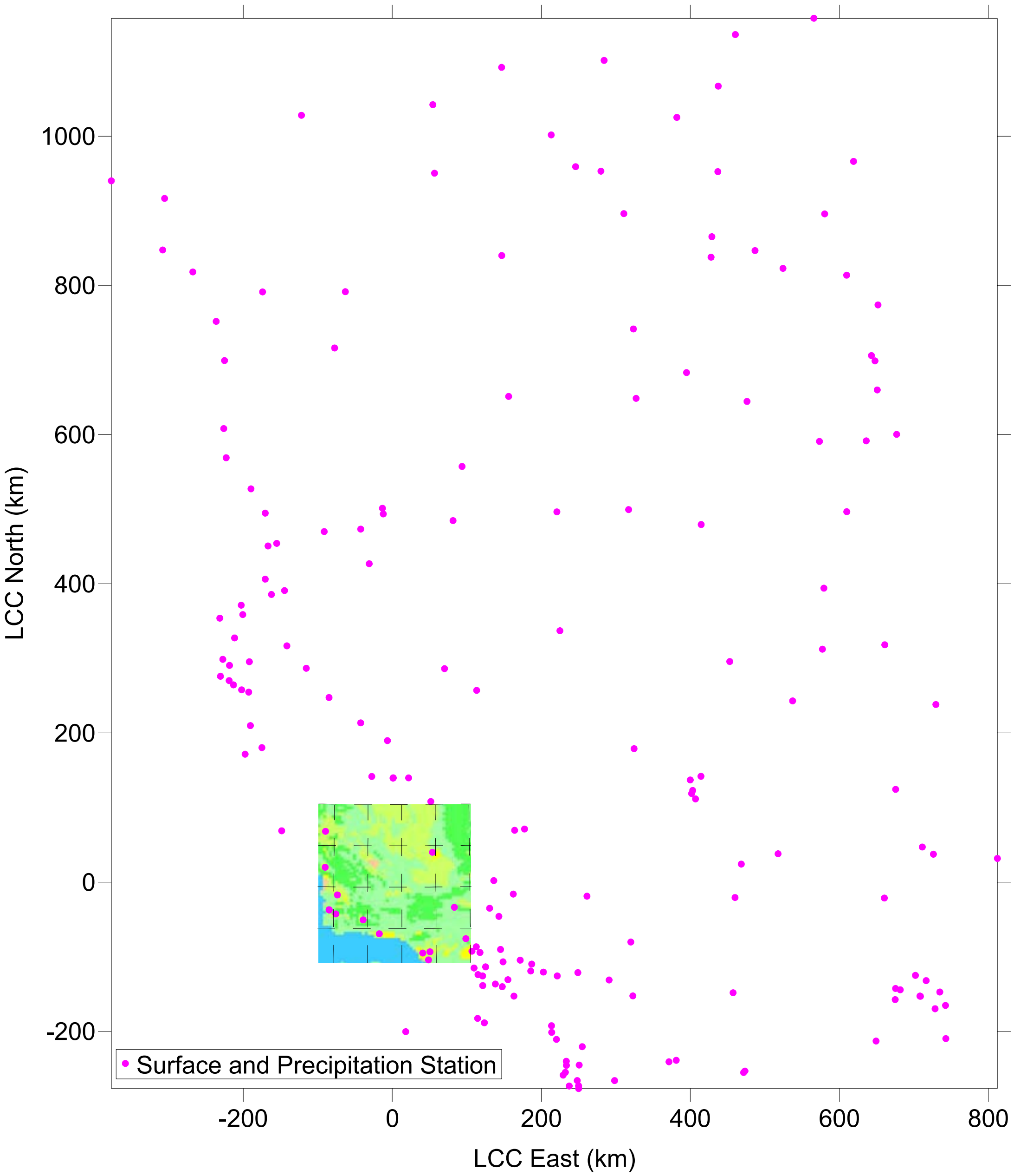


Figure 4
3-D Terrain Elevation Contours

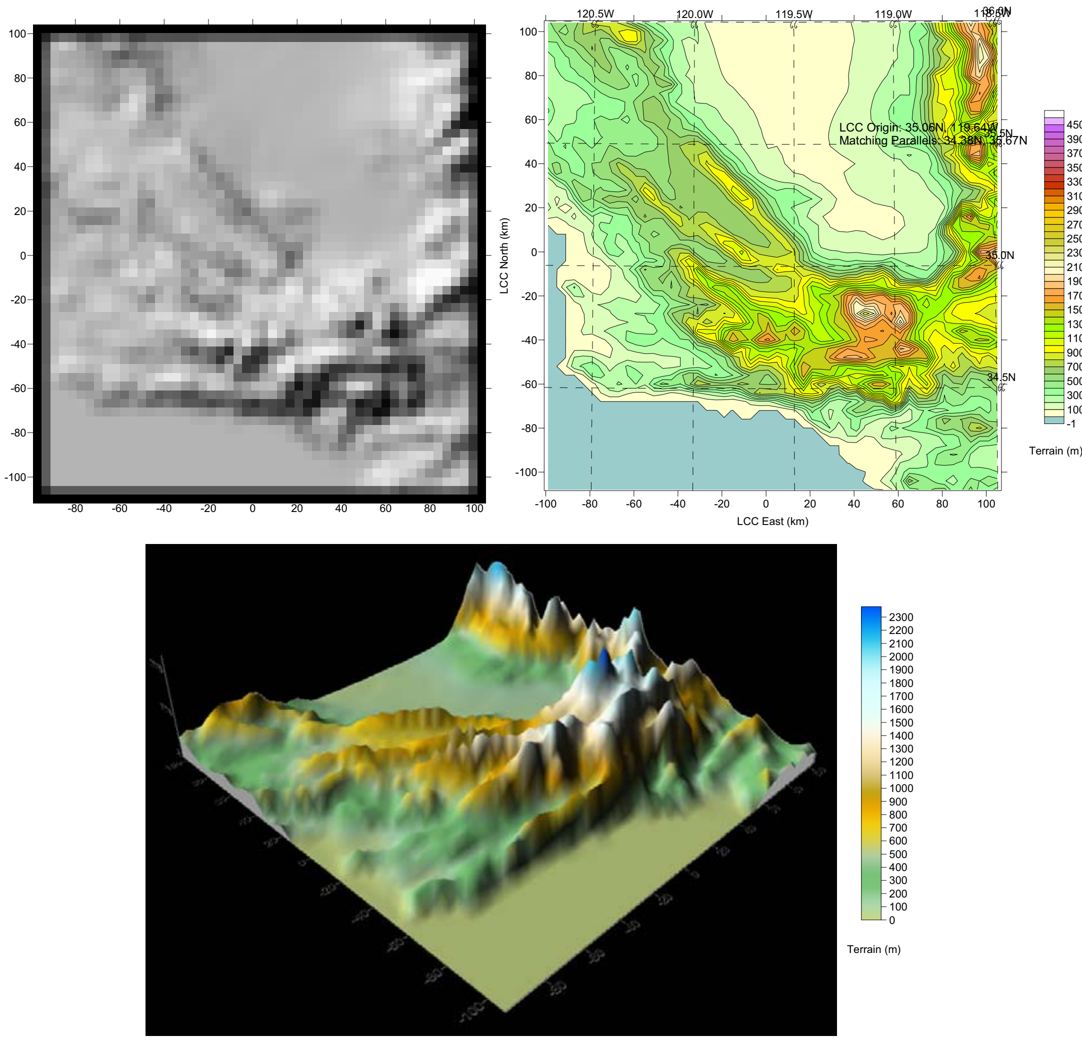
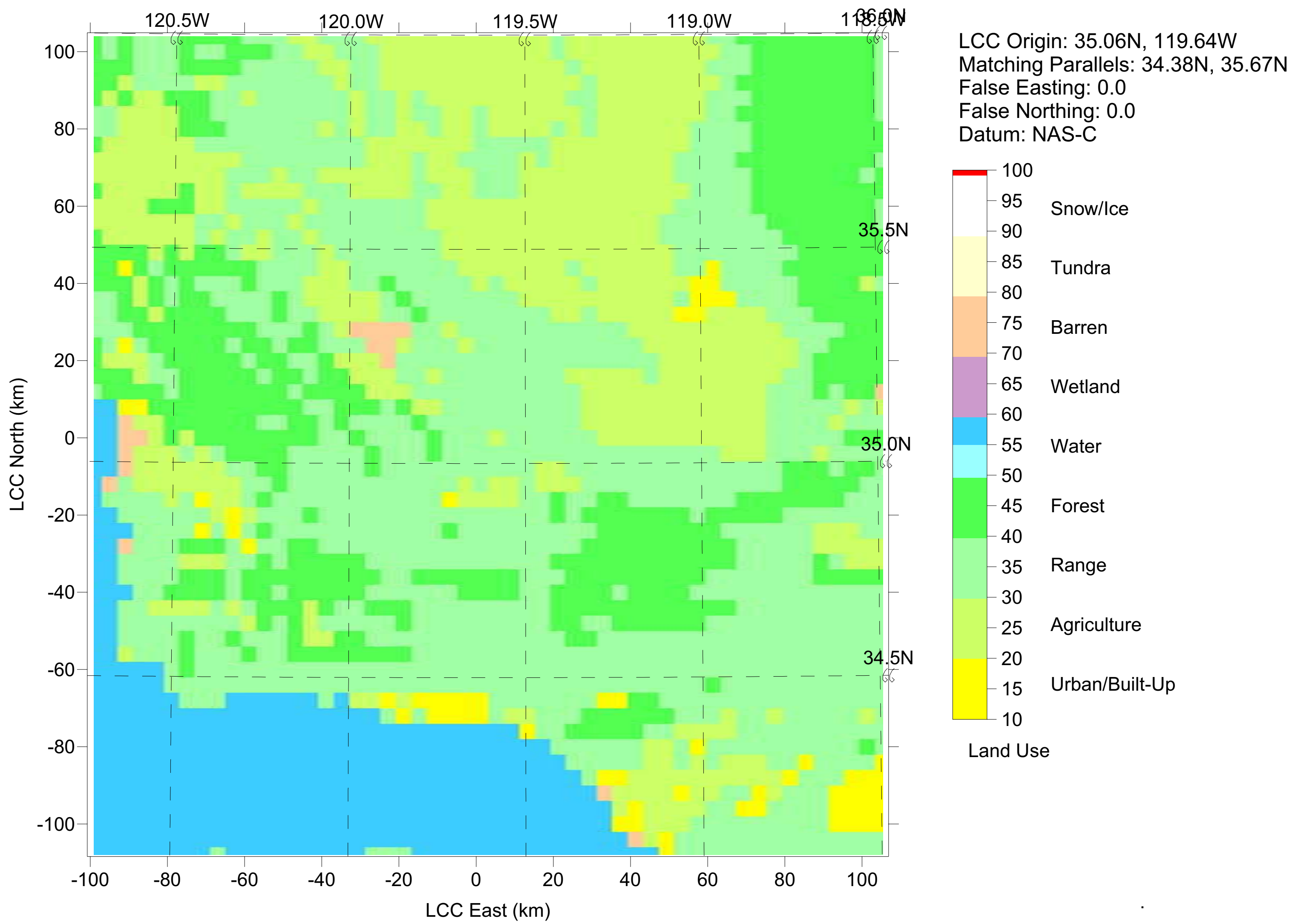


Figure 5
Land Use Land Cover



3.0 Receptors of Class I Areas

Receptors for all refined CALPUFF modeling of each Class I area were obtained from NPS' Class I Areas Receptor database (NPS, 2008). No modifications to the receptor locations or heights, as provided in the database, were made. Latitude/Longitude of the Class I receptor coordinates were converted to Lambert Conformal Conic (LCC) coordinate based on domain setup described in Section 1.2.

Three Class I areas are located within the region of the Project site: Dome Land Wilderness Area, Sequoia National Park, and San Rafael Wilderness Area. Table 1 lists the distances from the Project Site to the closest and farthest points of each Class I area.

Table 1
Class I Areas near the Project Site

Class I Areas	Distance from the Project Site (km)		Model Included?
San Rafael Wilderness Area	Closest	63	Yes
	Farthest	84	Yes
Dome Land Wilderness Area	Closest	110	No
	Farthest	169	No
Sequoia National Park	Closest	123	No
	Farthest	177	No

NPS does not anticipate any significant air quality impact at Sequoia National Park, based on the distance (123 km) from the Project Site, and the low emissions from proposed Project. Dome Land Wilderness Area is located in the range of 110 km to 169 km from the Project Site. Based on the distance, the low emissions from proposed Project, and the dominant wind direction at Bakersfield monitoring station (dominant wind is blowing from northwest, while the Dome Land Wilderness Area is located northeast of the Project Site), it was not anticipated that there will be any significant air quality impact at Dome Land Wilderness Area. Consequently, the original 2009 Project analysis did not include these two Class I areas. The closest parts of the San Rafael Wilderness are located beyond 31.1 miles (50 km) and within 62.1 miles (100 km) from the Project Site; thus, only San Rafael Wilderness Class I area was included in the Air Quality Relative Values (AQRV) analysis. On June 2, 2010, U.S. Forest Service agreed that this revised Project analysis may include only the San Rafael Wilderness Area. Therefore, Dome Land Wilderness Area and Sequoia National Park were not included in this revised Project analysis.

3.1 Sources Included in CALPUFF Modeling

Required emissions in CALPUFF correspond with the needed analysis and include maximum short-term rates for increment and visibility impacts, as well as maximum annual emissions for species deposition and increment comparison. Because of the various operations involved and potential occurrence during a specific period, the CALPUFF modeled sources and emissions included potential overlapping operations.

The maximum Potential-to-Emit (PTE) emission rate for each averaging time period is shown in Revised Table 2. The maximum emission rates shown in Revised Table 2 in units of grams per second were converted from the corresponding maximum emission rates expressed in units of either pounds per hour, pounds per day or tons per year contained in the emissions inventory. The maximum PTE rates are conservatively estimated based on simultaneous worst-case operation of all sources at the facility (please note that the auxiliary boiler was excluded in the short-term modeling analysis because the auxiliary boiler will not operate when the HRSG turbine is operating).

The stack parameters used in the CALPUFF modeling for all sources are shown in Revised Table 3.

The 3-hour averaged emission rate was used for the 3-hour SO_2 impact analysis. The 24-hour averaged emission rate was used for the 24-hour SO_2 and 24-hour PM_{10} impact analyses, and visibility impairment impact analysis. The annual emission rate was used for the annual NO_x, annual SO_2, and annual PM_{10} impact analyses as well as nitrogen and sulfur deposition analyses.

Since last submittal of the CALPUFF modeling report in August 2009, the emission rates of the Project sources have been modified. The Project refinements primarily consists of revisions associated with the need for more startups and shutdowns to account for offline turbine washing that is recommended by GE for maintenance.

The Project would still produce about 250 megawatts (MW) of baseload power and 390 gross MW from the combined cycle plant that is fed by the Gasification Block. The Project refinements are within the 473-acre Project Site and do not result in any additional disturbed areas beyond the Site that were not previously evaluated. In addition, the refinements are not expected to result in any substantial changes to the schedule, costs, workforce, or traffic during construction or operations, or equipment use during construction, as presented in the Revised AFC.

The Project refinements examined in this document are outlined below for each affected source.

Cooling Towers

No revisions were made to the operation or emissions from the cooling towers. For 24-hour analysis, the hourly maximum PTE rate was used. For annual analysis, the annual averaged emission rates were used based on 8,322 hours of operation.

It was assumed that 60 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, 40 percent of PM emissions were modeled as PM_{10} (Coarse Particulate Matter, PMC) and 60 percent of PM emissions were modeled as $PM_{2.5}$ (Fine Particulate Matter, PMF).

Diesel Emergency Generators

The maintenance operation schedule was changed to 52 hours per year for each engine. Emission factors for U.S. EPA Offroad Tier 4 engines were used, as discussed in the Applicant response to CEC Data Request 30.

For 1-hour averaging period, the maximum, PTE 1-hour emission rate was used. For 3-hour and 24-hour averaging periods, the analysis assumed that the emergency generator is operated for two hours; therefore, the analysis used the suspended emission rates during the 3-hour and

24-hour averaging periods, respectively. Only one emergency generator will be operated for these short-term averaging periods. For annual analysis, the annual averaged emission rates was used based upon 52 hours per year of operation per engine, and emissions from both engines were included in the annual analysis.

It was assumed that 100 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, total PM emissions were modeled directly as $PM_{2.5}$ (PMF).

CTG/HRSG

To account for the CTG washes and other possible maintenance, 10 hot startups were added, thus the number of startups and shutdowns was revised to:

- Cold startups = 10 per year
- Hot startups = 20 per year
- Shutdowns = 30 per year
- Normal Operations with Duct Burning = 8,257 hours per year
- Total Hours of operations = 8,322 hours per year (95 percent)

In the Revised AFC and subsequent AFC Amendment, a duct burner heating value of 500 million British thermal units (MMBtu) per hour (hr) was incorrectly used as the higher heating value (HHV) in the emission calculations. However, that value is actually the lower heating value (LHV). The calculations have been revised to use the correct duct burner heating value of 550 MMBtu/hr HHV. This resulted in the CTG/heat recovery system generator (HRSG) hourly emissions increasing slightly for sulfur dioxide (SO_2) when firing natural gas, and all pollutants except for PM_{10}/$PM_{2.5}$ when cofiring natural gas and syngas.

The worst 1-hour emissions were taken from the maximum rates of cold startup, hot startup, shutdown, or normal operation during 1-hour period. The worst 3-hour and 24-hour SO_2 emissions were taken from 3-hours and 24-hours of normal operation, respectively (calculation assumes that startup and shutdown SO_2 emissions will always be lower than the normal operational maximum SO_2 emissions). The 24-hour averaged emissions for NO_x and PM_{10} were estimated based on a maximum of 1 cold startup, 1 hot startup, 1 shutdown, with the remainder of the time at maximum normal operating emissions. HRSG used maximum emissions from either natural gas, synthetic gas, co-firing scenarios based on maximum startups and shutdowns in any given period of time. For annual analysis, the maximum annual averaged emission rates from either natural gas, synthetic gas, co-firing scenarios was used.

The CALPUFF modeling included speciation of emissions according to the NPS' Particulate Matter Speciation (PMS) method for natural gas combustion turbines. Although the CTG/HRSG will primarily burn hydrogen-rich fuel, no speciation data are available for the hydrogen-rich fuel, thus it is expected that the speciation should be similar to that for natural gas. Also the worst-case emissions used in the modeling were mostly from cases involving natural gas combustion. Applying the PMS methodology, 67 percent of total SO_2 was speciated into SO_2 and 33 percent of total SO_2 was speciated into SO_4. Also, the total PM emissions from CTG/HRSG were speciated into EC and SOA. The EC was speciated again into $PM_{0.05}$, $PM_{0.01}$, $PM_{0.15}$, $PM_{0.20}$, $PM_{0.25}$, and $PM_{1.0}$ (indicated as PM0005, PM0010, PM0015, PM0020, PM0025, and PM0100 in the modeling, respectively). Direct emissions of the remaining species, nitric acid (HNO_3) and nitrate (NO_3), were assumed to be zero for the natural gas and hydrogen-rich fuel burning sources of the Project. The modeled emissions are shown in Revised Table 4 (3-hour averaged), Revised Table 5 (24-hour averaged), and Revised Table 6 (annual averaged). The EC size distribution is shown in Table 7. In addition, total PM emissions were separately modeled as INCPM without speciation for incremental PM analysis. The INCPM was modeled using the same control file that the speciated PM was modeled.

Diesel Emergency Fire Water Pump

Emission factors for U.S. EPA Offroad Tier 4 engines were used as discussed in the response to CEC data request 30.

For 1-hour averaging period, the maximum, Potential-to-Emit (PTE) 1-hour emission rate was used. For 3-hour and 24-hour averaging periods, the analysis assumed that the emergency fire water pump is operated for two hours; therefore, the analysis used the suspended emission rates during the 3-hour and 24-hour averaging periods, respectively. For annual analysis, the annual averaged emission rate was used based upon 100 hours per year of operation.

It was assumed that 100 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, total PM emissions were modeled directly as $PM_{2.5}$ (PMF).

Auxiliary Boiler

SJVAPCD determined that SCR was BACT for the auxiliary boiler; therefore, the NO_x emissions from the boiler were reduced. The boiler is now a source of ammonia.

The auxiliary boiler was exempted for the short-term averaging period analysis because the auxiliary boiler (AUX_BOIL) will not operate on the same day that the HRSG turbine (HRSGSTK) operates. For annual analysis, the annual averaged emissions were estimated based on 2,190 hours per year of operation, and the modeling analysis included annual emissions from the auxiliary boiler with the HRSG emissions.

It was assumed that 100 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, total PM emissions were modeled directly as $PM_{2.5}$ (PMF).

Tail Gas Thermal Oxidizer

No revisions were made to the operation or emissions from the tail gas thermal oxidizer, although the emission calculations were updated to ensure incineration from one stream at a time was examined. Annual emissions are slightly lower due to new calculations.

The analysis used the hourly maximum PTE emission rate for each averaging time period. For annual analysis, the annual averaged emission rates were used based on 8,460 hours of normal operation and 300 hours of startup scenario.

It was assumed that 100 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, total PM emissions were modeled directly as $PM_{2.5}$ (PMF).

CO_2 Vent

Criteria pollutant emissions from the CO_2 vent did not change from those presented previously. There are no emissions of criteria pollutants except CO from the source; therefore, the CALPUFF analysis did not need to include any emissions from the source.

SRU Flare

To more accurately account for the time expected to startup/shutdown the gasifier, the SRU flare may flare for up to 40 hours per year. The worst-case 1-hour and 3-hour emission rates were taken from 1 hour and 3 hours of Startup/Shutdown flaring, respectively. The worst-case 24-hour emission rates were estimated based on approximately 12 hours of Startup/Shutdown flaring and the remainder in pilot operation. For annual analysis, the emission rates were estimated based on 40 hours of Startup/Shutdown flaring and 8,760 hours of pilot operation.

It was assumed that 100 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, total PM emissions were modeled directly as $PM_{2.5}$ (PMF).

Gasification Flare

During the turbine washes, hydrogen-rich fuel will be diverted to the gasification flare. It is expected to take 12 hours for a turbine wash, during which time the gasifier will operate at a reduced capacity (70 percent). Four turbine washes are planned annually, which add up to 81,400 MMBtu/yr of flaring. The total planned usage of the gasifier flare is expected to be 196,600 MMBtu/yr of flaring.

Each CTG wash is expected to take 12 hours, although 24 hours were considered for worst-case daily emission estimation. It is expected that up to 1,695 MMBtu/hr of shifted syngas could be flared during a turbine wash. The worst-case short-term emission rates were taken from maximum emission rates either from offline CTG wash operation, startup/shutdown operation, or pilot operation during the corresponding averaging period. For annual analysis, the emission rates were estimated based on summation of offline CTG wash operation, startup/shutdown operation and 8,760 hours of pilot operation.

It was assumed that 100 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, total PM emissions were modeled directly as $PM_{2.5}$ (PMF).

Gasifier Refractory Heaters

Based on operations from similar facilities, the Applicant determined that each refractory heater needs to be permitted to operate up to 1,200 hours per year. For estimating worst-case hourly and daily emissions, two heaters may operate at full load for the entire period. The analysis used gasifier warming vent stacks A and B, which have worst dispersion characteristics. For annual analysis, the emissions from all three heaters (A, B, and C) were included (total 3,600 hours per year of operation). The vendor-provided emission factors for NO_2 and CO are higher than the U.S. EPA AP-42 emission factors previously used to estimate these emissions.

It was assumed that 100 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, total PM emissions were modeled directly as $PM_{2.5}$ (PMF).

Feed Stock - Dust Collection

No revisions were made to the operation or emissions from the dust collection.

Maximum dust collector PM emission rate was estimated based on expected supplier guarantee of 0.005 grain/scf outlet loading. For 24-hour analysis, the maximum 24-hour averaging emission rate was used. For annual analysis, the maximum annual averaged emission rate was used.

It was assumed that 29.2 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, 70.8 percent of PM emissions were modeled as PM_{10} (PMC) and 29.2 percent of PM emissions were modeled as $PM_{2.5}$ (PMF).

Rectisol Flare

No revisions were made to the operation or emissions from the rectisol flare. The rectisol flare operation remains for emergency purposes only. However, the analysis used maximum emission rates for each averaging period based on pilot operation. For annual analysis, the annual averaged emission rates were estimated based on 8,760 hours per year of pilot operation.

It was assumed that 100 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate.

Revised Table 2
Maximum Emission Rates of Each Averaging Time Period

Source	3-hr (g/s)	24-hr (g/s)				Annual (g/s)			
	SO_2	NO_x	SO_2	$PM_{2.5}$	PM_{10}	NO_x	SO_2	$PM_{2.5}$	PM_{10}
ASUCOOL1	-	-	-	0.01710	0.02849	-	-	0.01624	0.02707
ASUCOOL2	-	-	-	0.01710	0.02849	-	-	0.01624	0.02707
ASUCOOL3	-	-	-	0.01710	0.02849	-	-	0.01624	0.02707
ASUCOOL4	-	-	-	0.01710	0.02849	-	-	0.01624	0.02707
PWCOOL1	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL2	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL3	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL4	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL5	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL6	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL7	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL8	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL9	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL10	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL11	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL12	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
PWCOOL13	-	-	-	0.02290	0.03816	-	-	0.02175	0.03626
GASCOOL1	-	-	-	0.01799	0.02998	-	-	0.01709	0.02848
GASCOOL2	-	-	-	0.01799	0.02998	-	-	0.01709	0.02848
GASCOOL3	-	-	-	0.01799	0.02998	-	-	0.01709	0.02848
GASCOOL4	-	-	-	0.01799	0.02998	-	-	0.01709	0.02848
EMERGEN1 [a]	0.00235	0.03382	0.00029	0.00473	0.00473	0.00241	2.09E-05	0.00034	0.00034
EMERGEN2 [a]	-	-	-	-	-	0.00241	2.09E-05	0.00034	0.00034
HRSGSTK	0.85996	6.93283	0.85996	2.49475	2.49475	4.83355	0.81539	2.36760	2.36760
FIREPUMP	0.00047	0.01931	5.88E-05	0.00019	0.00019	0.00264	8.05E-06	2.64E-05	2.64E-05

Revised Table 2
Maximum Emission Rates of Each Averaging Time Period (Continued)

Source	3-hr (g/s)	24-hr (g/s)				Annual (g/s)			
	SO_2	NO_x	SO_2	$PM_{2.5}$	PM_{10}	NO_x	SO_2	$PM_{2.5}$	PM_{10}
AUX_BOIL [b]	-	-	-	-	-	0.02684	0.00913	0.02237	0.02237
TAIL_TO	0.25200	0.30240	0.25200	0.01008	0.01008	0.30240	0.24346	0.01008	0.01008
CO2_VENT	-	-	-	-	-	-	-	-	-
SRUFLARE	2.32766	0.27443	1.16387	0.00686	0.00686	0.00702	0.01071	0.00018	0.00018
GF_FLARE	0.59800	14.94990	0.59800	0.00019	0.00019	0.20581	0.00341	0.00019	0.00019
GASVENTA [c]	0.00463	0.54432	0.00463	0.01814	0.01814	0.07456	0.00063	0.00249	0.00249
GASVENTB [c]	0.00463	0.54432	0.00463	0.01814	0.01814	0.07456	0.00063	0.00249	0.00249
GASVENTC [c]	-	-	-	-	-	0.07456	0.00063	0.00249	0.00249
DC1	-	-	-	0.00878	0.03007	-	-	0.00170	0.00582
DC2	-	-	-	0.02224	0.07615	-	-	0.00430	0.01474
DC3	-	-	-	0.01202	0.04115	-	-	0.01060	0.03631
DC4	-	-	-	0.00768	0.02631	-	-	0.00678	0.02321
DC5	-	-	-	0.00737	0.02523	-	-	0.00650	0.02227
DC6	-	-	-	0.00078	0.00267	-	-	0.00012	0.00040
RC_FLARE	7.72E-05	0.00454	7.72E-05	0.00011	0.00011	0.00454	7.72E-05	0.00011	0.00011

Notes:
a. The analysis assumed that only one generator operates at any short-term period. The emission is from EMERGEN1, which results worst impact among 2 emergency generators during short-term period.
b. Auxiliary boiler is not fired at the same time that the HRSG is operating.
c. There are three gasifiers. Up to two gasifiers warming will be operational at any one time. The emission is from GASVENTA and GASVENTB, which result worst impact among three gasifiers.

g/s = grams per second
NO_x = oxides of nitrogen
PM_{10} = particulate matter 10 microns or less in diameter
$PM_{2.5}$ = particulate matter 2.5 microns or less in diameter
SO_2 = sulfur dioxide

Revised Table 3
Source Location and Parameters

Source ID	Source Description	UTM Easting	UTM Northing	LCC X	LCC Y	Base Elevation	Stack Height	Stack Temperature	Stack Velocity	Stack Diameter
		(m)	(m)	(km)	(km)	(m)	(m)	(K)	(m/s)	(m)
ASUCOOL1	ASU Cooling Tower	282891.3	3912002.1	23.21883	30.06171	87.93	16.76	299.9	7.98	9.14
ASUCOOL2	ASU Cooling Tower	282906.2	3912002.4	23.23371	30.06243	87.93	16.76	299.9	7.98	9.14
ASUCOOL3	ASU Cooling Tower	282922.2	3912002.1	23.24975	30.06254	87.93	16.76	299.9	7.98	9.14
ASUCOOL4	ASU Cooling Tower	282937.3	3912001.4	23.26486	30.06224	87.93	16.76	299.9	7.98	9.14
PWCOOL1	Power Block Cooling Tower	283031.9	3912001.1	23.35941	30.06445	87.93	16.76	299.9	7.98	9.14
PWCOOL2	Power Block Cooling Tower	283046.3	3912000.9	23.37385	30.06469	87.93	16.76	299.9	7.98	9.14
PWCOOL3	Power Block Cooling Tower	283061.6	3912001.0	23.38915	30.06519	87.93	16.76	299.9	7.98	9.14
PWCOOL4	Power Block Cooling Tower	283076.9	3912000.0	23.40443	30.06463	87.93	16.76	299.9	7.98	9.14
PWCOOL5	Power Block Cooling Tower	283092.1	3912000.0	23.41960	30.06494	87.93	16.76	299.9	7.98	9.14
PWCOOL6	Power Block Cooling Tower	283107.9	3912000.0	23.43540	30.06545	87.93	16.76	299.9	7.98	9.14
PWCOOL7	Power Block Cooling Tower	283122.7	3911999.4	23.45019	30.06518	87.93	16.76	299.9	7.98	9.14
PWCOOL8	Power Block Cooling Tower	283137.8	3911999.3	23.46529	30.06555	87.93	16.76	299.9	7.98	9.14
PWCOOL9	Power Block Cooling Tower	283153.5	3911999.5	23.48100	30.06609	87.93	16.76	299.9	7.98	9.14
PWCOOL10	Power Block Cooling Tower	283168.8	3911999.2	23.49627	30.06622	87.93	16.76	299.9	7.98	9.14
PWCOOL11	Power Block Cooling Tower	283183.7	3911999.6	23.51118	30.06702	87.93	16.76	299.9	7.98	9.14
PWCOOL12	Power Block Cooling Tower	283199.5	3911999.0	23.52698	30.06690	87.93	16.76	299.9	7.98	9.14
PWCOOL13	Power Block Cooling Tower	283275.2	3911998.1	23.60261	30.06800	87.93	16.76	299.9	7.98	9.14
GASCOOL1	Gasification Cooling Tower	283214.6	3911999.4	23.54206	30.06768	87.93	16.76	299.9	7.98	9.14
GASCOOL2	Gasification Cooling Tower	283228.6	3911998.4	23.55610	30.06699	87.93	16.76	299.9	7.98	9.14
GASCOOL3	Gasification Cooling Tower	283244.7	3911998.9	23.57215	30.06791	87.93	16.76	299.9	7.98	9.14
GASCOOL4	Gasification Cooling Tower	283259.1	3911998.1	23.58660	30.06755	87.93	16.76	299.9	7.98	9.14
EMERGEN1	Emergency Generator1	282948.3	3912172.0	23.27130	30.23302	87.93	6.10	677.6	67.38	0.37
EMERGEN2	Emergency Generator2	282948.3	3912172.0	23.27130	30.23302	87.93	6.10	677.6	67.38	0.37
HRSGSTK	HRSG Stack	282940.0	3912211.5	23.26200	30.27232	87.93	65.00	344.3	11.55	6.10
FIREPUMP	Fire Water Pump Diesel Engine	282770.9	3912535.5	23.08432	30.59164	87.93	6.10	727.6	47.52	0.21
AUX_BOIL	Auxiliary Boiler	282955.1	3912273.0	23.27539	30.33414	87.93	24.38	422.0	9.20	1.37
TAIL_TO	Tail Gas Thermal Oxidizer	283049.1	3912112.7	23.37362	30.17650	87.93	50.29	922.0	7.45	0.76

Revised Table 3
Source Location and Parameters (Continued)

Source ID	Source Description	UTM Easting	UTM Northing	LCC X	LCC Y	Base Elevation	Stack Height	Stack Temperature	Stack Velocity	Stack Diameter
		(m)	(m)	(km)	(km)	(m)	(m)	(K)	(m/s)	(m)
CO_2_VENT	CO_2 Vent	283045.7	3912389.7	23.36286	30.45327	87.93	79.25	291.5	55.92	1.07
SRUFLARE	SRU Flare	283042.4	3912097.7	23.36739	30.16128	87.93	76.20	1273.0	20.00	1.09
GF_FLARE	Gasification Flare	283064.5	3912472.6	23.37946	30.53658	87.93	76.20	1273.0	20.00	5.47
GASVENTA	Gasifier Warming Vent A	283212.0	3912340.0	23.53038	30.40798	87.93	64.01	338.7	26.39	0.30
GASVENTB	Gasifier Warming Vent B	283212.0	3912316.0	23.53102	30.38400	87.93	64.01	338.7	26.39	0.30
GASVENTC	Gasifier Warming Vent C	283212.0	3912292.0	23.53166	30.36001	87.93	64.01	338.7	26.39	0.30
DC1	FeedStock-DustCollection	283318.3	3913064.3	23.61730	31.13474	87.93	13.87	291.9	15.06	0.51
DC2	FeedStock-DustCollection	283322.2	3912661.6	23.63192	30.73237	87.93	51.97	291.9	14.90	0.81
DC3	FeedStock-DustCollection	283150.4	3912310.2	23.46956	30.37655	87.93	53.80	291.9	14.66	0.56
DC4	FeedStock-DustCollection	283240.8	3912679.7	23.55013	30.74824	87.93	51.97	291.9	15.70	0.43
DC5	FeedStock-DustCollection	283147.0	3912671.2	23.45654	30.73726	87.93	24.23	291.9	15.06	0.43
DC6	FeedStock-DustCollection	283145.7	3912324.0	23.46453	30.39022	87.93	53.80	291.9	14.19	0.23
RC_FLARE	Rectisol Flare	283064.7	3912479.1	23.37950	30.54304	87.93	76.20	1273.0	20.00	0.10

Notes:
Assumed that the temperature of cooling tower is 8K degree higher than the annual averaged temperature value from the AERMET meteorological data at Bakersfield monitoring station.
Assumed that the temperature of dust collection is the annual averaged value from the AERMET meteorological data at Bakersfield monitoring station..

K	=	Kelvin
km	=	kilometer
LCC	=	Lambert Conformal Conic
m	=	meter
m/s	=	meters per second
UTM	=	Universal Transverse Mercator

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Revised Table 4
3-hour Averaged Emission Inventory for CALPUFF (3-hour SO_2 Increment Analysis)

Sources (g/s)	SO_2	SO_4	NO_x	HNO_3	NO_3	INCPM	PMC (PM_{10})	PMF ($PM_{2.5}$)	EC						SOA
									PM0005	PM0010	PM0015	PM0020	PM0025	PM0100	
EMERGEN1	2.35E-03	-	4.06E-01	-	-	4.73E-03	-	4.73E-03	-	-	-	-	-	-	-
HRSGSTK	5.73E-01	4.30E-01	2.10E+01	-	-	2.49E+00	-	-	9.36E-02	1.56E-01	1.43E-01	9.36E-02	6.86E-02	6.86E-02	1.44E+00
FIREPUMP	4.70E-04	-	2.32E-01	-	-	1.93E-04	-	1.93E-04	-	-	-	-	-	-	-
TAIL_TO	2.52E-01	-	3.02E-01	-	-	1.01E-02	-	1.01E-02	-	-	-	-	-	-	-
SRUFLARE	2.33E+00	-	5.44E-01	-	-	6.86E-03	-	6.86E-03	-	-	-	-	-	-	-
GF_FLARE	5.98E-01	-	1.49E+01	-	-	1.89E-04	-	1.89E-04	-	-	-	-	-	-	-
GASVENTA	4.63E-03	-	5.44E-01	-	-	1.81E-02	-	1.81E-02	-	-	-	-	-	-	-
GASVENTB	4.63E-03	-	5.44E-01	-	-	1.81E-02	-	1.81E-02	-	-	-	-	-	-	-
RC_FLARE	7.72E-05	-	4.54E-03	-	-	1.13E-04	-	1.13E-04	-	-	-	-	-	-	-

Notes:
(g/s) = grams per second
EC = Elemental Carbon
HNO_3 = nitric acid
INCPM = total particulate matter emission
NO_x = oxides of nitrogen
NO_3 = nitrate
PM0005 = particulate matter 0.05 microns or less in diameter
PM0010 = particulate matter 0.1 microns or less in diameter
PM0015 = particulate matter 0.15 microns or less in diameter
PM0020 = particulate matter 0.2 microns or less in diameter
PM0025 = particulate matter 0.25 microns or less in diameter
PM0100 = particulate matter 1 microns or less in diameter
$PM_{2.5}$ = particulate matter 2.5 microns or less in diameter
PM_{10} = particulate matter 10 microns or less in diameter
PMC = Coarse Particulates
PMF = Fine Particulates
SO_2 = sulfur dioxide
SO_4 = sulfate compound
SOA = Secondary Organic Aerosol

Revised Table 5
24-hour Averaged Emission Inventory for CALPUFF (24-hour NO_x, SO_2, and PM_{10} Increment and Visibility Analyses)

Sources (g/s)	SO_2	SO_4	NO_x	HNO_3	NO_3	INCPM	PMC (PM_{10})	PMF ($PM_{2.5}$)	SOA						EC
									PM0005	PM0010	PM0015	PM0020	PM0025	PM0100	
ASUCOOL1	-	-	-	-	-	2.85E-02	1.14E-02	1.71E-02	-	-	-	-	-	-	-
ASUCOOL2	-	-	-	-	-	2.85E-02	1.14E-02	1.71E-02	-	-	-	-	-	-	-
ASUCOOL3	-	-	-	-	-	2.85E-02	1.14E-02	1.71E-02	-	-	-	-	-	-	-
ASUCOOL4	-	-	-	-	-	2.85E-02	1.14E-02	1.71E-02	-	-	-	-	-	-	-
PWCOOL1	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL2	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL3	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL4	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL5	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL6	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL7	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL8	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL9	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL10	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL11	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL12	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
PWCOOL13	-	-	-	-	-	3.82E-02	1.53E-02	2.29E-02	-	-	-	-	-	-	-
GASCOOL1	-	-	-	-	-	3.00E-02	1.20E-02	1.80E-02	-	-	-	-	-	-	-
GASCOOL2	-	-	-	-	-	3.00E-02	1.20E-02	1.80E-02	-	-	-	-	-	-	-
GASCOOL3	-	-	-	-	-	3.00E-02	1.20E-02	1.80E-02	-	-	-	-	-	-	-
GASCOOL4	-	-	-	-	-	3.00E-02	1.20E-02	1.80E-02	-	-	-	-	-	-	-
EMERGEN1	2.94E-04	-	3.38E-02	-	-	4.73E-03	-	4.73E-03	-	-	-	-	-	-	-
HRSGSTK	5.73E-01	4.30E-01	6.93E+00	-	-	2.49E+00	-	-	9.36E-02	1.56E-01	1.43E-01	9.36E-02	6.86E-02	6.86E-02	1.44E+00
FIREPUMP	5.88E-05	-	1.93E-02			1.93E-04	-	1.93E-04							
TAIL_TO	2.52E-01	-	3.02E-01	-	-	1.01E-02	-	1.01E-02	-	-	-	-	-	-	-
SRUFLARE	1.16E+00	-	2.74E-01	-	-	6.86E-03	-	6.86E-03	-	-	-	-	-	-	-
GF_FLARE	5.98E-01	-	1.49E+01	-	-	1.89E-04	-	1.89E-04	-	-	-	-	-	-	-
GASVENTA	4.63E-03	-	5.44E-01	-	-	1.81E-02	-	1.81E-02	-	-	-	-	-	-	-
GASVENTB	4.63E-03	-	5.44E-01	-	-	1.81E-02	-	1.81E-02	-	-	-	-	-	-	-
DC1	-	-	-	-	-	3.01E-02	2.13E-02	8.78E-03	-	-	-	-	-	-	-
DC2	-	-	-	-	-	7.61E-02	5.39E-02	2.22E-02	-	-	-	-	-	-	-
DC3	-	-	-	-	-	4.11E-02	2.91E-02	1.20E-02	-	-	-	-	-	-	-
DC4	-	-	-	-	-	2.63E-02	1.86E-02	7.68E-03	-	-	-	-	-	-	-
DC5	-	-	-	-	-	2.52E-02	1.79E-02	7.37E-03	-	-	-	-	-	-	-
DC6	-	-	-	-	-	2.67E-03	1.89E-03	7.78E-04	-	-	-	-	-	-	-
RC_FLARE	7.72E-05	-	4.54E-03	-	-	1.13E-04	-	1.13E-04	-	-	-	-	-	-	-

Notes:
(g/s) = grams per second
EC = Elemental Carbon
HNO_3 = nitric acid
INCPM = total particulate matter emission
NO_x = oxides of nitrogen
NO_3 = nitrate
PM0005 = particulate matter 0.05 microns or less in diameter
PM0010 = particulate matter 0.1 microns or less in diameter
PM0015 = particulate matter 0.15 microns or less in diameter
PM0020 = particulate matter 0.2 microns or less in diameter
PM0025 = particulate matter 0.25 microns or less in diameter
PM0100 = particulate matter 1 microns or less in diameter
$PM_{2.5}$ = particulate matter 2.5 microns or less in diameter
PM_{10} = particulate matter 10 microns or less in diameter
PMC = Coarse Particulates
PMF = Fine Particulates
SO_2 = sulfur dioxide
SO_4 = sulfate compound
SOA = Secondary Organic Aerosol

Revised Table 6
Annual Averaged Emission Inventory for CALPUFF (Annual NO_x, SO_2, and PM_{10} Increment and Deposition Analyses)

Sources (g/s)	SO_2	SO_4	NO_x	HNO_3	NO_3	INCPM	PMC (PM_{10})	PMF ($PM_{2.5}$)	SOA						EC
									PM0005	PM0010	PM0015	PM0020	PM0025	PM0100	
ASUCOOL1	-	-	-	-	-	2.71E-02	1.08E-02	1.62E-02	-	-	-	-	-	-	-
ASUCOOL2	-	-	-	-	-	2.71E-02	1.08E-02	1.62E-02	-	-	-	-	-	-	-
ASUCOOL3	-	-	-	-	-	2.71E-02	1.08E-02	1.62E-02	-	-	-	-	-	-	-
ASUCOOL4	-	-	-	-	-	2.71E-02	1.08E-02	1.62E-02	-	-	-	-	-	-	-
PWCOOL1	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL2	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL3	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL4	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL5	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL6	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL7	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL8	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL9	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL10	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL11	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL12	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
PWCOOL13	-	-	-	-	-	3.63E-02	1.45E-02	2.18E-02	-	-	-	-	-	-	-
GASCOOL1	-	-	-	-	-	2.85E-02	1.14E-02	1.71E-02	-	-	-	-	-	-	-
GASCOOL2	-	-	-	-	-	2.85E-02	1.14E-02	1.71E-02	-	-	-	-	-	-	-
GASCOOL3	-	-	-	-	-	2.85E-02	1.14E-02	1.71E-02	-	-	-	-	-	-	-
GASCOOL4	-	-	-	-	-	2.85E-02	1.14E-02	1.71E-02	-	-	-	-	-	-	-
EMERGEN1	2.09E-05	-	2.41E-03	-	-	3.37E-04	-	3.37E-04	-	-	-	-	-	-	-
EMERGEN2	2.09E-05	-	2.41E-03	-	-	3.37E-04	-	3.37E-04	-	-	-	-	-	-	-
HRSGSTK	5.44E-01	4.08E-01	4.83E+00	-	-	2.37E+00	-	-	8.88E-02	1.48E-01	1.36E-01	8.88E-02	6.51E-02	6.51E-02	1.37E+00
FIREPUMP	8.05E-06	-	2.64E-03	-	-	2.64E-05	-	2.64E-05	-	-	-	-	-	-	-
AUX_BOIL	9.13E-03	-	2.68E-02	-	-	2.24E-02	-	2.24E-02	-	-	-	-	-	-	-
TAIL_TO	2.43E-01	-	3.02E-01	-	-	1.01E-02	-	1.01E-02	-	-	-	-	-	-	-
SRUFLARE	1.07E-02	-	7.02E-03	-	-	1.76E-04	-	1.76E-04	-	-	-	-	-	-	-
GF_FLARE	3.41E-03	-	2.06E-01	-	-	1.89E-04	-	1.89E-04	-	-	-	-	-	-	-
GASVENTA	6.34E-04		7.46E-02			2.49E-03	-	2.49E-03							
GASVENTB	6.34E-04	-	7.46E-02	-	-	2.49E-03	-	2.49E-03	-	-	-	-	-	-	-
GASVENTC	6.34E-04	-	7.46E-02	-	-	2.49E-03	-	2.49E-03	-	-	-	-	-	-	-
DC1	-	-	-	-	-	5.82E-03	4.12E-03	1.70E-03	-	-	-	-	-	-	-
DC2	-	-	-	-	-	1.47E-02	1.04E-02	4.30E-03	-	-	-	-	-	-	-
DC3	-	-	-	-	-	3.63E-02	2.57E-02	1.06E-02	-	-	-	-	-	-	-
DC4	-	-	-	-	-	2.32E-02	1.64E-02	6.78E-03	-	-	-	-	-	-	-
DC5	-	-	-	-	-	2.23E-02	1.58E-02	6.50E-03	-	-	-	-	-	-	-
DC6	-	-	-	-	-	4.00E-04	2.83E-04	1.17E-04	-	-	-	-	-	-	-
RC_FLARE	7.72E-05	-	4.54E-03	-	-	1.13E-04	-	1.13E-04	-	-	-	-	-	-	-

Notes:
(g/s) = grams per second
EC = Elemental Carbon
HNO_3 = nitric acid
INCPM = total particulate matter emission
NO_x = oxides of nitrogen
NO_3 = nitrate

PM0005 = particulate matter 0.05 microns or less in diameter
PM0010 = particulate matter 0.1 microns or less in diameter
PM0015 = particulate matter 0.15 microns or less in diameter
PM0020 = particulate matter 0.2 microns or less in diameter
PM0025 = particulate matter 0.25 microns or less in diameter
PM0100 = particulate matter 1 microns or less in diameter
$PM_{2.5}$ = particulate matter 2.5 microns or less in diameter

PM_{10} = particulate matter 10 microns or less in diameter
PMC = Coarse Particulates
PMF = Fine Particulates
SO_2 = sulfur dioxide
SO_4 = sulfate compound
SOA = Secondary Organic Aerosol

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Table 7
Size Distribution of EC (NPS, 2009)

Species Name	Size Distribution (%)	Geometric Mass Mean Diameter (microns)	Geometric Std. Deviation (microns)
SO_4	100	0.48	0.50
NO_3	100	0.48	0.50
PM0005	15	0.05	0.00
PM0010	40	0.10	0.00
PM0015	63	0.15	0.00
PM0020	78	0.20	0.00
PM0025	89	0.25	0.00
PM0100	100	1.00	0.00

Notes:
NO_3 = nitrate
NPS = National Park Service
PM0005 = particulate matter 0.05 microns or less in diameter
PM0010 = particulate matter 0.1 microns or less in diameter
PM0015 = particulate matter 0.15 microns or less in diameter
PM0020 = particulate matter 0.2 microns or less in diameter
PM0025 = particulate matter 0.25 microns or less in diameter
PM0100 = particulate matter 1 microns or less in diameter
SO_4 = sulfate compound
EC = Elemental Carbon

3.2 CALPUFF Parameters

The CALPUFF options were selected to follow U.S. EPA's recommended settings for regulatory modeling or WRAP's BART modeling, along with suggestions from USFS. USFS suggested that a background concentration for ammonia in the San Joaquin Valley of 20 ppb should be used in the CALPUFF analysis.

Based upon the comments from USFS, the CALPUFF modeling analysis sets the regulatory default switch (MREG = 1) to force all model inputs to the U.S. EPA-approved regulatory settings.

Size parameters for dry deposition of nitrate, sulfate, and PM_{10} particles were based on default CALPUFF model options. Chemical parameters for gaseous dry deposition and wet scavenging coefficients were based on default values presented in the CALPUFF User's Guide. Calculation of total nitrogen deposition includes the contribution of nitrogen resulting from the ammonium ion of the ammonium sulfate compound. For the CALPUFF runs that incorporate deposition and chemical transformation rates (i.e. deposition and visibility), the full chemistry option of CALPUFF was turned on (MCHEM = 1). The nighttime loss for SO_2, NO_x and HNO_3 was set at 0.2 percent per hour, 2 percent per hour and 2 percent per hour, respectively. CALPUFF was also configured to allow predictions of SO_2, sulfate (SO_4), NO_x, HNO_3, NO_3 and PM_{10} using the MESOPUFF II chemical transformation module.

Hourly ozone concentration files (OZONE.DAT) were obtained from the WRAP's BART modeling website for the same years (2001 through 2003) as the meteorological data. Monthly background ozone concentration for missing data from hourly ozone concentration file was set to 80 ppb. The monthly background ammonia concentration was set to 20 ppb, as recommended by the USFS for other projects in the San Joaquin Valley.

As described in Section 3.2, emissions were speciated in accordance with the NPS' PMS guideline (http://www2.nature.nps.gov/air/permits/ect/index.cfm). In doing so, the sulfur emissions were speciated to relative sulfur constituents of SO_2 and SO_4 to better account for gas to particulate conversion and visibility effects.

3.3 PSD Class I Increment Significance Analysis

CALMET/CALPUFF (Refined CALPUFF) was used to model ambient air impacts of NO_2, PM_{10}, and SO_2 from the emission sources, and the modeling results were compared to PSD Class I Increment modeling significance thresholds. Modeling techniques for comparison with the PSD Class I Increments in this analysis are the same as in previous analyses for the HECA Project. The sources were modeled at full PTE for this analysis. The full chemistry option of CALPUFF was turned on (MCHEM =1, MESOPUFF II scheme), and a deposition option was turned on (MWET = 1 and MDRY = 1). The 3-hour averaged maximum SO_2 emission rate were modeled for 3-hour SO_2 increment analysis. Emission of total SO_2 from the natural gas combustion turbines was speciated based on NPS' PMS guideline. The 24-hour averaged maximum emission rates were modeled for 24-hour SO_2 and PM_{10} increment analyses. The annual averaged emission rates were modeled for annual averaged NO_x, SO_2, and PM_{10} increment analyses. For 24-hour and annual PM incremental analyses, the total PM emission ("INCPM" in the modeling) was modeled without speciation, and the INCPM was treated as fine particulate matter in terms of geometric characteristics.

3.4 Class I Area Visibility Reduction Analysis

Refined CALPUFF was used to evaluate the potential for visibility reduction. Emissions from all sources are described in Section 3.2 above, including the speciation of emissions.

The emissions of fourteen chemical species, SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}, $PM_{2.5}$, $PM_{0.05}$, $PM_{0.01}$, $PM_{0.15}$, $PM_{0.20}$, $PM_{0.25}$, $PM_{1.0}$, and SOA, were modeled in CALPUFF to predict the visibility impact based on PMS for natural gas turbine. Because only SO_2 emissions estimates were provided, one-third of the estimated SO_2 emission was assumed to be SO_4 emissions, and the remaining two-thirds remained as SO_2 emissions. For CTG/HRSG, the total PM emissions were speciated into EC and SOA. The EC is speciated again into $PM_{0.05}$, $PM_{0.01}$, $PM_{0.15}$, $PM_{0.20}$, $PM_{0.25}$, and $PM_{1.0}$ (indicated as PM0005, PM0010, PM0015, PM0020, PM0025, and PM0100 in the modeling, respectively). For the other sources such as cooling towers, the total PM emissions were modeled as $PM_{2.5}$ (PMF) and PM_{10} (Coarse Particulates, PMC).

CALPOST was used to post-process the estimated 24-hour averaged ammonium nitrate, ammonium sulfate, EC, SOA, $PM_{2.5}$ (PMF) and PM_{10} (PMC) concentrations into an extinction coefficient value for each day at each modeled receptor, using the three years of CALMET meteorological data. To do so, it required the use of extinction efficiency values.

All the PM species ($PM_{0.05}$, $PM_{0.01}$, $PM_{0.15}$, $PM_{0.20}$, $PM_{0.25}$, and $PM_{1.0}$) were grouped as EC. Default extinction efficiencies of $PM_{2.5}$ (PMF), PM_{10} (PMC), SOA, EC, soil, ammonium sulfate, and ammonium nitrate were used. $PM_{2.5}$ emission was assigned as PMF, with an extinction coefficient of 1.0. Any remaining PM_{10}, which is larger than 2.5 microns, was modeled as PMC, with an extinction coefficient of 0.6.

The CALPUFF modeling analysis used visibility calculation Method 2 (MVISBK = 2).

Background visibility and extinction coefficient values from the FLAG Phase I Report (December 2000) were used for the visibility reduction analysis. Background values for hygroscopic concentration, without adjustment for relative humidity (RH), (0.6 $\mu g/m^3$) and the non-hygroscopic concentration (4.5 $\mu g/m^3$) are reported for western wilderness areas. Therefore, BKSO4 = hygroscopic 0.6/3 = 0.2 and BKSOIL = non-hygroscopic = 4.5 were used. Modeled visibility reductions for each modeled year were compared to the level of acceptable change (LAC) of 5.0 percent and 10.0 percent.

3.5 Total Nitrogen and Sulfur Deposition Analysis

Refined CALPUFF was used to evaluate the potential for nitrogen and sulfur deposition; the techniques presented below are the same as those used in previous analyses. All sources were modeled at full PTE for this analysis. The annual average emission rates were used for the annual averaged nitrogen and sulfur deposition analyses. The NPS's PMS for natural gas combustion turbines was applied to speciate the emissions of SO_2 and PM from HRSG and turbine as it was done for increment and visibility analyses.

The total deposition rates for each pollutant were obtained by summing the modeled wet and/or dry deposition rates as follows.

For sulfur (S) deposition, the wet and dry fluxes of sulfur dioxide and sulfate are calculated, normalized by the molecular weight of S, and expressed as total S. Total nitrogen (N) deposition is the sum of N contributed by wet and dry fluxes of HNO_3, NO_3^-, ammonium sulfate ($(NH_4)_2SO_4$), and ammonium nitrate (NH_4NO_3) and the dry flux of oxides of nitrogen (NO_x).

The total modeled nitrogen and sulfur deposition rates were compared to the National Park Service (NPS)/Fish and Wildlife Service (FWS) Deposition Analysis Threshold (DAT) for western states. The DAT for nitrogen and sulfur are each 0.005 kilogram per hectare per year (kg/ha-yr), which is equal to 1.59E-11 g/m^2-s.

4.0 CALPUFF MODELING RESULTS

Three years of CALPUFF modeling results are provided in Revised Table 8 through Revised Table 10. The model-predicted criteria pollutant increment concentrations were compared to the proposed Class I area Significant Impact Levels (SIL). Each criteria pollutant concentration is less than the corresponding SIL for the San Rafael Wilderness Class I area.

Modeled visibility reductions for each modeled year were compared to the level of acceptable extinction change (LAC) of 5.0 percent. The visibility impact is greater than 5 percent, but less than 10 percent of cumulative modeling threshold. The number of days that exceeds 5 percent of extinction change is 3 days for 2001, 4 days for 2002, and 2 days for 2003.

The visibility modeling analysis was performed based on emission rates of conservative operating scenario.

- It was assumed that the gasification flare operate for 24-hours of offline CTG wash operation. It is expected to take 12 hours for a turbine wash and only four turbine washes are planned annually. For example, NO_x emission from offline CTG wash is approximately 2,000 times greater than pilot operation. However, the model conservatively assumed that a full 24-hours of this event happens everyday.
- SRU Flare emission for 24-hour period was estimated based on 12 hours of startup/shutdown flaring and remaining in pilot operation. This startup/shutdown is anticipated to occur only 40 hours of total per year. However, the model conservatively assumed that a full 24-hour of this event happens everyday.
- Emergency generator and firewater pump will be operated for 52 hours per year and 100 hours per year, respectively. However, the model conservatively assumed that a full 24-hours of this event happens everyday.
- HRSG NO_x emission was estimated based on 1 cold startup, 1 hot startup, and 1 shutdown for 24-hour period. The model conservatively assumed that a full 24-hour of this event happens everyday.

Not only each source emission rates was estimated based on worst-case scenario, the model conservatively assumed that all the sources will be operated at the same time everyday. Based on this conservative emission rates, it is expected that no significant visibility impact would occur due to the proposed Project.

Deposition thresholds of total N and total S are both 0.005 kg/ha/yr, which is equal to 1.59E-11 g/m^2-s. Total N and S deposition impact do not exceed the threshold.

None of the results of criteria pollutant increment and deposition analyses exceeded the threshold, and the maximum visibility impact was less than 10 percent with only 2 to 4 days of exceedance of 5 percent despite of conservative operating scenario; therefore, the proposed Project sources will not have a significant impact on ambient air quality of the San Rafael Wilderness Class I area. Since the criteria pollutant concentration and deposition is less than its corresponding significance level, the Project sources will not have a significant impact on either terrestrial resources such as soil and vegetation or aquatic resources. Therefore, no further analyses, including additional AQRV impacts were conducted.

Revised Table 8
PSD Class I Increment Significance Analysis – CALPUFF Results

Class I Area	Pollutant	Annual NO_x	3-hr SO_2	24-hr SO_2	Annual SO_2	24-hr PM_{10}	Annual PM_{10}
	Unit	μg/m³	μg/m³	μg/m³	μg/m³	μg/m³	Annual
	Threshold	0.1	1	0.2	0.08	0.32	0.16
San Rafael	2001	3.93E-03	2.34E-01	5.27E-02	7.36E-04	8.70E-02	3.33E-03
Wilderness	2002	4.27E-03	2.46E-01	5.05E-02	8.65E-04	7.72E-02	3.80E-03
Area	2003	4.44E-03	2.70E-01	4.42E-02	8.71E-04	9.33E-02	3.78E-03
Exceed?		No	No	No	No	No	No

Notes:
μg/m³ = micrograms per cubic meter
NO_x = oxides of nitrogen
PM_{10} = particulate matter 10 microns or less in diameter
PSD = Prevention of Significant Deterioration
SO_2 = sulfur dioxide

Revised Table 9
Visibility Analysis – CALPUFF Results

Class I Area	Pollutant	No.of Days > 5%	No.of Days >10%	Max Extinction Change	Day of Maximum Extinction Change
	Unit	Days	Days	%	Julian Day
	Threshold	0	0	10	
San Rafael Wilderness Area	2001	3	0	9.48	308
	2002	4	0	8.07	287
	2003	2	0	6.65	247
Exceed?				No	

Revised Table 10
Total Nitrogen and Sulfur Deposition Analysis – CALPUFF Results

Class I Area	Pollutant	Deposition N	Deposition S
	Unit	g/m²/s	g/m²/s
	Threshold	1.59E-11	1.59E-11
San Rafael Wilderness Area	2001	9.75E-13	3.85E-13
	2002	1.23E-12	5.04E-13
	2003	1.25E-12	4.54E-13
Exceed?		No	No

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