hydrogen energy

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| 08-AFC-8 | |
| DATE | JUN 24 2009 |
| RECD. | JUL 02 2009 |

June 24, 2009

Gerardo Rios
Chief, Permits Office
US Environmental Protection Agency
Air Division (AIR-3)
75 Hawthorne St.
San Francisco, CA 94105

Subject: **Submittal of Prevention of Significant Deterioration Application – Hydrogen Energy California**

Dear Mr. Rios:

Hydrogen Energy International LLC (HEI) proposes to build a nominally rated 250 (approximate) net megawatt (MW) integrated gasification combined cycle power generation unit at a site in Kern County, California. The attached document is an application for a Prevention of Significant Deterioration (PSD) of air quality permit for the "HECA" project.

HECA will be a state-of-the-art integrated gasification combined cycle gas turbine power plant, will produce low-carbon baseload electricity by capturing carbon dioxide ($CO_2$) and transporting to Elk Hills Oil Field for enhanced oil recovery (EOR) and sequestration, and will utilize the best available technology for environmental performance.

A Revised Application for Certification for this unit was filed with the California Energy Commission (Docket # 08-AFC-8 filed on May 28, 2009). An Authority to Construct / Permit to Operate Application will be filed with the San Joaquin Valley Air Pollution Control District (SJVAPCD).

The attached application includes a complete PSD application and supporting information. Please contact me at (562) 276-1511 or Mark Strehlow at (510) 874-3055 if you have any questions or require additional information.

One World Trade Center, Suite 1600, Long Beach, CA 90831-1600 Main (+1) 562-276-1543 Fax (+1) 562-276-1571 www.hydrogenenergy.com

Sincerely,

Gregory D. Skannal
Manager, HSSE
Hydrogen Energy International LLC

Attachment: Application

Copy: California Energy Commission
Mark Strehlow, URS

# Prevention of Significant Deterioration (PSD) Permit Application

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

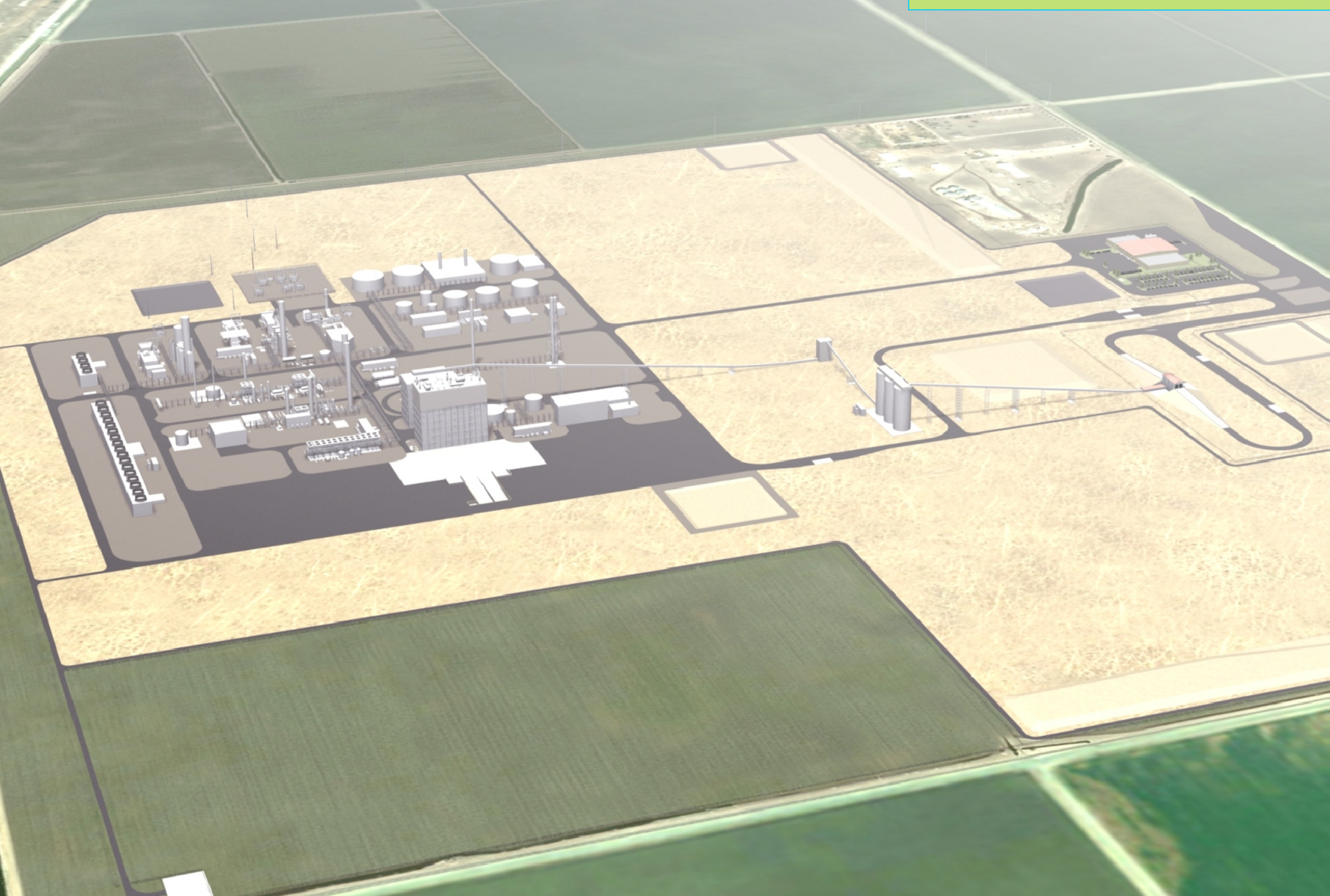
June 2009

**Prepared for:**
Hydrogen Energy International LLC

hydrogen energy

**Submitted to:**
U.S. Environmental Protection Agency
Region 9

**Prepared by:**
URS



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## Acronyms and Abbreviations

| | |
|---|---|
| AAQS | Ambient Air Quality Standard |
| AFC | Application for Certification |
| AGR | acid gas removal |
| APN | Assessor's Parcel Number |
| APE | area of potential effect |
| Applicant | Hydrogen Energy International LLC |
| AQMP | air quality management plan |
| AQRVs | Air quality-related values |
| ASU | air separation unit |
| ATC | Authority to Construct |
| BACT | Best Available Control Technology |
| CAAA | Clean Air Act Amendment of 1990 |
| CAAQS | California Ambient Air Quality Standard |
| CAISO | California Independent System Operator |
| CB | Construction Battalion |
| CCS | cryptocrystalline |
| CEMS | Continuous Emission Monitoring Systems |
| CEC | California Energy Commission |
| CEQA | California Environmental Quality Act |
| CO | carbon monoxide |

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| | |
|---|---|
| $CO_2$ | carbon dioxide |
| CRM | Cultural Resource Monitor |
| CTG | combustion turbine generator |
| DOC | Determination of Compliance |
| DOE | Department of Energy |
| EOR | enhanced oil recovery |
| EPA | Environmental Protection Agency (federal) |
| gpm | gallons per minute |
| HECA | Hydrogen Energy California |
| HEI | Hydrogen Energy International LLC |
| HRSG | heat recovery steam generator |
| IGCC | Integrated Gasification Combined Cycle |
| MW | megawatt |
| $\mu g/m^3$ | micrograms per cubic meter |
| NAAQS | National Ambient Air Quality Standard |
| $NO_2$ | nitrogen dioxide |
| NPS | National Park Service |
| $PM_{2.5}$ | fine particulate matter |
| $PM_{10}$ | particulate matter |
| ppmvd | parts per million volumetric dry |
| Project | Hydrogen Energy California |
| PSD | Prevention of Significant Deterioration |
| PTO | permit to operate |
| SCR | selective catalytic reduction |
| SJVAB | San Joaquin Valley Air Basin |
| SJVAPCD | San Joaquin Valley Air Pollution Control District |
| SIP | state implementation plan |
| $SO_2$ | sulfur dioxide |
| TGTU | tail gas treating unit |
| USFS | U.S. Forest Service |
| USGS | U. S. Geological Survey |
| VOCs | volatile organic compounds |

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This Prevention of Significant Deterioration (PSD) Permit application is for the construction and operation of the Hydrogen Energy California Integrated Gasification Combined Cycle (IGCC) Project (HECA or Project). This PSD permit application is a stand-alone document submitted with the intention of obtaining a PSD permit from the U.S. Environmental Protection Agency (EPA). An Application for Certification (AFC) and an Authority to Construct/Permit to Operate application have also been submitted to the California Energy Commission (CEC) and the San Joaquin Valley Air Pollution Control District (SJVAPCD), respectively.

Hydrogen Energy International LLC (HEI or Applicant) is jointly owned by BP Alternative Energy North America Inc. and Rio Tinto Hydrogen Energy LLC. HEI is proposing to build the Project in Kern County, California. The Project will produce low-carbon baseload electricity by capturing carbon dioxide ($CO_2$) and transporting it for enhanced oil recovery (EOR) and sequestration.

The 473-acre Project Site is located approximately 7 miles west of the outermost edge of the city of Bakersfield and 1.5 miles northwest of the unincorporated community of Tupman in western Kern County, California, as shown in Figure 1-1, Project Vicinity Map. HEI is also acquiring an additional 628 acres of land adjacent to the Project Site, herein referred to as “Controlled Area” (see Figure 1-2). HEI will own this property and have control over public access and future land use. For the purposes of the Air Quality analysis, impacts were determined outside of both the Project Site and the Controlled Area.

The Project Site is near an oil producing area known as the Elk Hills Field. The entire Project Site is presently used for agricultural purposes, including cultivation of cotton, alfalfa, and onions. Existing surface elevations vary from about 282 feet to 291 feet above mean sea level.

The Project will gasify petroleum coke (or blends of petroleum coke and coal, as needed) to produce hydrogen to fuel a combustion turbine operating in combined cycle mode. The Gasification Unit feeds a 390 gross megawatt (MW) combined cycle plant. The net electrical generation output from the Project will provide California with approximately 250 MW, net, of low-carbon baseload power to the grid. The Gasification Unit will also capture approximately 90 percent of the carbon dioxide from the syngas at steady-state operation, which will be transported to the Elk Hills Field for $CO_2$ EOR and Sequestration. In addition, approximately 100 MW of natural gas generated peaking power will be available from the Project.

The HECA sources will be equipped with Best Available Control Technology (BACT) to control criteria pollutant emissions. The sources and control measures are discussed in Appendix B and listed in Table 2-6.

Operational emission estimates were based on full load operation of the sources comprising the power block, gasification block, and supporting systems. The emissions from power generation and gasification processes includes maximum supplemental firing and consideration of startup/shutdown events. An air dispersion modeling analysis was conducted to demonstrate that maximum modeled impacts are below applicable federal PSD significant impact levels for all criteria pollutants for which there are PSD increments. Air dispersion modeling also indicates that nitrogen dioxide ($NO_2$), sulfur dioxide ($SO_2$), carbon monoxide (CO), particulate matter ($PM_{10}$), and fine particulate matter ($PM_{2.5}$) impacts from the operation of the Project when combined with background are below the Ambient Air Quality Standard (AAQS) and would not significantly contribute to the existing violations of the state $PM_{10}$ or ozone standards, or negatively impact visibility in Class I areas. See Chapter 2 for an explanation of federal, state, and local laws, ordinances, regulations, and standards. Criteria pollutant emissions are discussed in Chapter 5, and air dispersion modeling and compliance with ambient air quality standards and PSD increments are discussed in Chapter 6.

Air quality-related values (AQRVs) include visibility, terrestrial resources, and aquatic resources. AQRVs were assessed for the closest Class I area, which is the San Rafael Wilderness Area. A visibility analysis demonstrates that HECA will not significantly impact visibility. Maximum modeled annual $NO_2$ and $SO_2$ impacts from normal plant operations were assessed to ensure any nitrogen or sulfur deposition would not impact terrestrial or aquatic resources. All impacts are below U.S. Forest Service (USFS) significance criteria. Details of the analysis are included in Section 7.

## 1.1 PROJECT LOCATION

The Project Site consists of approximately 473 acres located near an oil producing area in Kern County, California, as shown in Figure 1-1, Vicinity Map. The Project Site is located in a predominantly agricultural area of the county, 1.5 miles northwest of the unincorporated community of Tupman. The 473-acre Project Site is located within Section 10 of Township 30 South, Range 24 East in Kern County. The Project Site Assessor's Parcel Numbers (APN) are as follows:

- Part of 159-040-16
- Part of 159-040-18

HEI is also acquiring an additional 628 acres of land adjacent to the Project Site, herein referred to as Controlled Area. HEI will own this property, and have control over public access and future land use. These areas are shown on Figure 1-2. The associated APNs of the Controlled Area are as follows:

- 159-040-02
- 159-040-04
- 159-040-11
- Remnant part of 159-040-16
- Remnant part of 159-040-18
- 159-190-09

The Project Site is predominantly used for agricultural purposes, including cultivation of cotton, alfalfa, and onions. The Project Site vicinity consists primarily of agricultural uses. Adjacent land uses include Adohr Road and agricultural uses to the north; Tupman Road and agricultural uses to the east, agricultural uses and an irrigation canal to the south; and a residence, structures (used for grain storage and organic fertilizer production), agricultural uses, and Dairy Road right of way to the west. The West Side/Outlet Canal, Kern River Flood Control Canal, and the California Aqueduct (State Water Project) are approximately 500, 700, and 1,900 feet south of the Project Site, respectively.

## 1.2 FACILITY DESCRIPTION

The preliminary plot plan for the Project is shown in Figure 1-3. The facility will gasify 100 percent petroleum coke (or blends of petroleum coke and coal, as needed) to produce hydrogen to fuel a combustion turbine operating in combined cycle mode. The Project will produce low carbon electricity while substantially reducing greenhouse gas emissions by capturing carbon dioxide ($CO_2$), transporting it for enhanced oil recovery (EOR), and sequestration.

Highlights of the Project are as follows:

- The Project is designed to operate with 100 percent petroleum coke from California refineries, and has the flexibility to operate with up to 75 percent thermal input (higher heating value) western bituminous coal.

- The feedstock will be gasified to produce a synthesis gas (syngas) that will be processed and purified to produce a hydrogen-rich gas, which will be used to fuel the combustion turbine for electric power generation. A portion of the product (hydrogen-rich gas) will also be used to supplementally fire the heat recovery steam generator (HRSG) that produces steam from the combustion turbine exhaust heat.
- At least 90 percent of the carbon in the raw syngas will be captured in a high-purity carbon dioxide stream during steady-state operation, compressed and transported by pipeline to the custody transfer point for injection into deep underground hydrocarbon reservoirs for $CO_2$ enhanced oil recovery and sequestration.
- Project greenhouse gas emissions (e.g., $CO_2$) and sulfur emissions will be reduced through carbon dioxide sequestration and state-of-the-art emission-control technology. The power produced by the Project will have a low-carbon emission profile significantly lower than would be produced by traditional fossil-fueled sources, including natural gas.
- The net electrical generation output from the Project will provide approximately 250 megawatts (MW) of low carbon baseload power to the grid, feeding major load sources to the north and to the south. In addition, approximately 100 MW of natural gas generated peaking power will be available from the Project.
- The water source for the Project will be brackish groundwater supplied by the Buena Vista Water Storage District, and treated on-site to meet Project standards. Potable water will be supplied by West Kern Water Bank for drinking and sanitary purposes.
- There will be no direct surface water discharge of industrial wastewater or storm water. Process wastewater will be treated on-site and recycled within the gasification and power plant systems. Other wastewaters from cooling tower blowdown and the water treatment plant will be collected and directed to one of two on-site plant wastewater Zero Liquid Discharge units.

The Project is designed with state-of-the-art emission-control technology. The gasification process will feature near zero sulfur emissions during steady-state operation. The Project is also designed to avoid flaring during steady-state operation, and to minimize flaring and sulfur emissions during startup and shut down operations.

The Project also includes the following off-site facilities, as shown on Figure 1-2, Project Location Map.

- **Electrical Transmission Line –** An electrical transmission line will interconnect the Project to Pacific Gas & Electric's (PG&E) Midway Substation. Two alternative transmission line routes are proposed; both alternatives are approximately 8 miles in length.
- **Natural Gas Supply Pipeline –** A natural gas interconnection will be made with PG&E or So Cal Gas natural gas pipelines, each of which is located southeast of the Project Site. The natural gas pipeline is approximately 8 miles in length.
- **Water Supply Pipelines –** The Project will utilize brackish groundwater supplied from the Buena Vista Water Storage District located to the northwest. The raw water supply pipeline will be approximately 15 miles in length. Potable water for drinking and sanitary use will be

supplied by West Kern Water District to the southeast. The potable water supply pipeline is approximately 7 miles in length.

- **Carbon Dioxide Pipeline –** The carbon dioxide pipeline will transfer the carbon dioxide captured during gasification from the Project Site southwest to the custody transfer point. Two alternative carbon dioxide pipeline routes are proposed; each of these alternatives is approximately 4 miles in length.

All temporary construction equipment laydown and parking, including construction parking, offices, and construction laydown areas, will be located on the Project Site.

The disturbed acreage associated with the Project is summarized in Table 1-1, Project Disturbed Acreage.

## Table 1-1
## Project Disturbed Acreage

| Project Component | Size | Approx. Linear Length (miles) | ROW Construction | ROW Permanent | Temporary Disturbance | Permanent Disturbance |
|---|---|---|---|---|---|---|
| Project Site | 473 acres | NA | NA | NA | 473 acres | 250 |
| Electrical transmission line | 25-foot diameter structural base (60 structures total) | 8 | 175 FT[1] | 150 FT | 24 acres | 0.67[2] |
| Natural gas pipeline | 16-inch diameter | 8 | 50 FT | 25 FT | 50[3] | 0.33[4] |
| Process Water pipeline | 20-inch diameter | 15 | 50 FT | 25 FT | 93[5] | 0.29[6] |
| Potable Water pipeline | 6-inch diameter | 7 | Accounted for in Natural Gas Line ROW | Accounted for in Natural Gas Line ROW | Accounted for in Natural Gas Line ROW | Accounted for in Natural Gas Line ROW |
| $CO_2$ pipeline | 12-inch diameter | 4 | 50 FT | 25 FT | 25[3] | 0.11[7] |
| Temporary Construction Areas | Accounted for in Project Site | NA | NA | NA | Accounted for in Project Site | None |
| **Total Project Disturbance** | | | | | **665** | **251.4** |

Source: HECA Project

**Notes:**

~ = approximately
$CO_2$ = carbon dioxide
ROW = right of way

[1] This is a maximum width required in areas where structures will be installed. However, total temporary disturbance along the entire route is calculated based on the following: (1) 150 FT x 150 FT area is required for each of the 60 structures, equaling 31 acres, and (2) 25-foot temporary roadway is required along the entire 8 mile line, equaling 24 acres.

[2] Consists of permanent ground disturbance associated with the base of the 60 new structures.

[3] Acreage includes the area required for the entry/exit pits.

[4] Acreage includes permanent disturbance occupied by the gas metering station located within the Controlled Area southeast of the Project Site.

[5] Acreage includes the 100 by 150 foot temporarily disturbed area required for the construction of each of five groundwater wells.

[6] Acreage includes the 50 by 50 foot permanent disturbed area required for each of five groundwater wells.

[7] Acreage includes two 50 by 50 valve boxes positioned along the pipeline route.

## 1.3 EMISSIONS CONTROL AND MONITORING

The Project is designed with state-of-the-art emission-control technology. Emissions control systems will be designed to meet the BACT levels for nitrogen oxides, carbon monoxide, sulfur dioxide, and volatile organic compounds (VOCs), as proposed in this application, based on the most current industry data and manufacturers' information. Project emission control systems are described in detail below.

### 1.3.1 SCR Emissions Control System

The selective catalytic reduction (SCR) system reduces nitrogen oxide emissions from the HRSG stack gases and a separate SCR system reduces nitrogen oxide emissions from the Auxiliary Combustion Turbine Generator (CTG), each by up to about 70 to 80 percent. Diluted 19 percent aqueous ammonia is injected into the stack gases upstream of a catalytic system, which converts nitrogen oxide and ammonia to nitrogen and water.

The expected components in the SCR system are as follows:

<u>Aqueous Ammonia Storage Tank</u> – The aqueous ammonia storage tank is a horizontal or vertical vessel which stores 16,000 gallons of 19 weight percent aqueous ammonia for the SCR system. The storage tank will be complete with relief valves, level gauges, local audio alarms, and will also be located inside a containment area.

<u>Aqueous Ammonia Forwarding Pumps</u> – The aqueous ammonia forwarding pumps will transfer aqueous ammonia from the storage tank to the aqueous ammonia vaporizer.

<u>Ammonia Vaporizer</u> – The aqueous ammonia vaporizer atomizes and vaporizes the ammonia and water solution. Plant air or steam will atomize the aqueous ammonia to assist in the vaporization. The energy to vaporize the aqueous ammonia will come from a slip stream of hot stack gas or by heating ambient air with a heating element.

<u>Vaporizer Blower</u> – The vaporizer blower delivers fresh air or recycled hot stack gas from the HRSG into the aqueous ammonia vaporizer.

<u>Ammonia Injection Grid</u> – Once the aqueous ammonia is properly vaporized, the ammonia is sent to an injection grid where the ammonia stream is divided into various injection points upstream of a catalyst. The flow of ammonia to each injection point can be balanced to provide optimum nitrogen oxide reduction.

<u>SCR Catalyst</u> – The SCR catalyst provides the surface area and the catalyst to react ammonia and nitrogen oxide to form nitrogen and water. The SCR catalyst will be installed in a reactor housing located within the HRSG at the proper flue gas temperature-point for good nitrogen oxide conversion.

### 1.3.2 CO Oxidation System

A carbon monoxide catalyst will be installed in the HRSG casing and in the CTG upstream of the SCR ammonia injection location to reduce carbon monoxide emissions. The carbon monoxide catalyst will oxidize the carbon monoxide and VOCs produced from the CTG and duct burners.

### 1.3.3 Continuous Emissions Monitoring System

Continuous Emission Monitoring Systems (CEMS) will be installed on several stack emission sources as required by applicable regulations and permit conditions. The CEMS will be designed, installed, and certified in accordance with the applicable SJVAPCD and EPA standards for analyzer performance, data acquisition, and data reporting. In general, it is expected that these systems will sample, analyze, and record stack emission data for several specified pollutants. CEMS will incorporate data handling and acquisition systems to automatically generate emissions data logs and compliance documentation. Alarms will alert operators if stack emissions exceed specified limits. Each CEMS system will undergo periodic calibration, audits, and testing to verify accuracy. It is anticipated that the following CEMS systems will be required for the indicated emissions:

- HRSG – nitrogen oxide, carbon monoxide, and oxygen
- Auxiliary CTG – nitrogen oxide, carbon monoxide, and oxygen
- Tail Gas Thermal Oxidizer – sulfur dioxide and oxygen
- Hydrogen-rich Fuel – Total sulfur

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

## 1.4 PROJECT SCHEDULE

The milestones for the Project are anticipated to be as follows:

| | |
|---|---|
| Completion of CEC permitting process | May 2011 |
| Start of construction | December 2011 |
| Completion of construction | December 2014 |
| Commissioning and initial startup | October 2014 through August 2015 |
| Full-scale operation of the Project | September 2015 |

## 1.5 PROJECT OWNERSHIP

HEI is jointly owned by BP Alternative Energy North America Inc. and Rio Tinto Hydrogen Energy LLC, with the prime objective of producing hydrogen for low-carbon power generation. HEI proposes to be the owner and operator of the IGCC facilities and has the option to purchase the 473-acre Project Site, as defined below, from the site owner. HEI also has the option to purchase 628 acres that comprise the Controlled Area.

The transmission line will be owned by HEI up to the point of interconnect (Midway Substation) as stipulated by the California Independent System Operator (CAISO). HEI will own the carbon dioxide ($CO_2$) pipeline up to the custody transfer point. Natural gas supply lines will be owned by PG&E or Southern California Gas Company. The process water supply line will be owned by Buena Vista Water District. The potable water supply line will be owned by West Kern Water District.

## 1.6 APPLICANT CONTACT INFORMATION

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email: mark_strehlow@urscorp.com


5/20/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-1_proj vicinity_8.5x11.ai

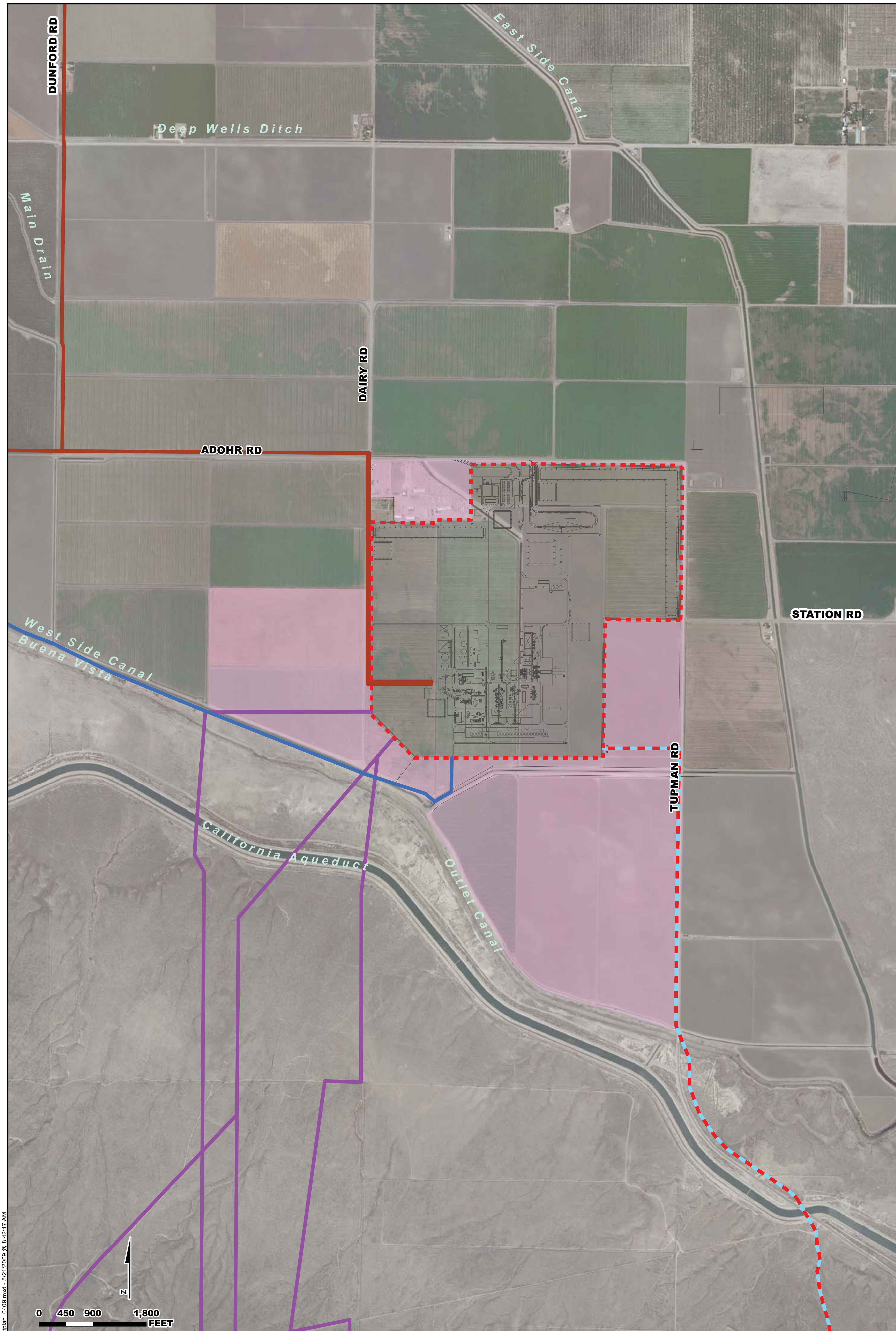
**PROJECT VICINITY**

May 2009
28067571

Hydrogen Energy California (HECA)
Kern County, California

URS

**FIGURE 1-1**




**LEGEND**

| | | |
|---|---|---|
| AFC Project Site | Carbon Dioxide | Potable Water/NG |
| Controlled Area | Natural Gas (NG) | Process Water |
| | Potable Water | Transmission |

**SITE PLAN**

May 2009
28067571

Hydrogen Energy California (HECA)
Kern County, California

URS

**FIGURE 1-2**

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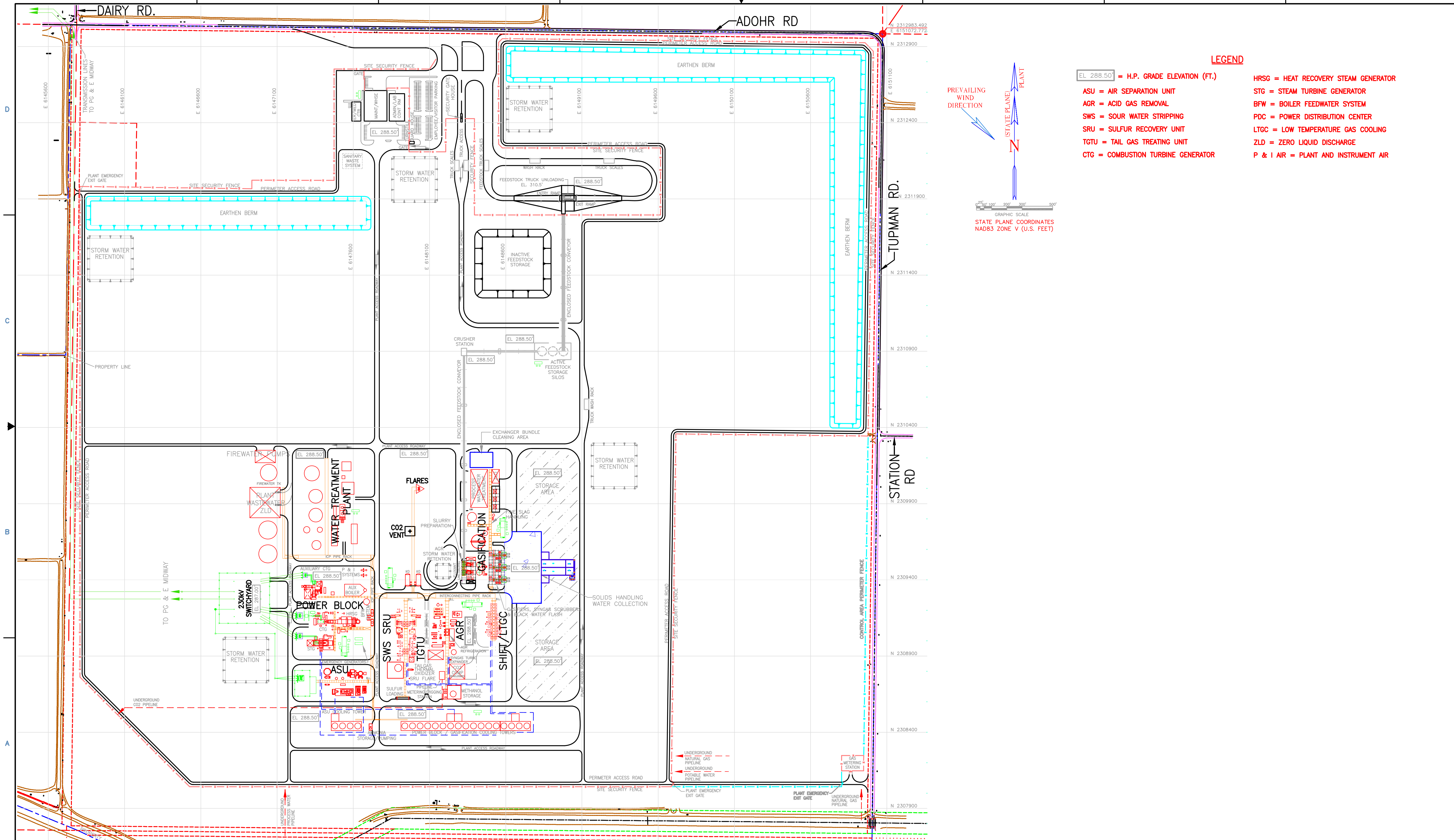
Aerial Photo, Digital Globe, June 1, 2008.




Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Preliminary Plot Plan; Drawing No: SK-250-1001, Rev. 0, 05/12/09

**PRELIMINARY PLOT PLAN**

May 2009
28067571

Hydrogen Energy California (HECA)
Kern County, California

URS

**FIGURE 1-3**

EPA has ultimate responsibility for ensuring, pursuant to the Clean Air Act Amendments of 1990 (CAAA), that all areas of the U.S. meet, or are making progress toward meeting, the national ambient air quality standards (NAAQS). The State of California falls under the jurisdiction of EPA Region 9, which is headquartered in San Francisco. EPA requires that all states submit State Implementation Plans (SIPs) for non-attainment areas that describe how the NAAQS will be achieved and maintained. Attainment plans must be approved by the California Air Resources Board (CARB) before they are submitted to EPA.

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

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

Applicable laws, ordinances, regulations and standards (LORS) related to the potential air quality impacts from the Project are described below, and shown in Table 2-1, Laws, Ordinances, Regulations, and Standards – Air Quality. These LORS are administered (either independently or cooperatively) by the SJVAPCD, EPA Region 9, the California Energy Commission (CEC), and CARB. The area of responsibility for each of these agencies is described below.

**Table 2-1**
**Laws, Ordinances, Regulations, and Standards – Air Quality**

| Laws, Ordinances, Regulations, and Standards | Applicability | Administering Agency |
|---|---|---|
| **Federal** | | |
| Clean Air Act 160-169A and implementing regulations, Title 42 United States Code (USC) 7470-7491 (42 USC 7470-7491; Title 40 Code of Federal Regulations (CFR) Parts 51 and 52 (40 CFR Parts 51 and 52) Prevention of Significant Deterioration Program) | Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of air pollution. PSD review applies to pollutants for which ambient concentrations are lower than NAAQS. | USEPA Region 9 |
| CAA 171-193, 42 USC 7501 et seq. (New Source Review) | Requires new source review (NSR) facility permitting for construction or modification of stationary sources. NSR applies to pollutants for which ambient concentrations are higher than NAAQS. | USEPA Region 9 |
| CAA 401 (Title IV), 42 USC 7651 (Acid Rain Program); SJVAPCD Regulation IV, Rule 2540 | Requires reductions in $NO_x$ and SO2 emissions. | SJVAPCD, with USEPA Region 9 oversight |
| CAA 501 (Title V), 42 USC 7661 (Federal Operating Permits Program) | Establishes comprehensive permit program for major stationary sources. | SJVAPCD, with USEPA Region 9 oversight |
| CAA 111, 42 USC 7411, 40 CFR Part 60 (New Source Performance Standards, or NSPS) | Establishes national standards of performance for new stationary sources. This rule incorporates the New Source Performance Standards from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR). | SJVAPCD, with USEPA Region 9 oversight |
| **State** | | |
| H&SC 44300-44384; Title 17 of The California Code of Regulations (17 CCR 93300-93300.5) Toxic “Hot Spots” Act | Requires preparation and biennial updating of facility emission inventory of hazardous substances; health risk assessments. | CARB |
| H&SC 41700 | Provides that no person shall discharge from any source quantities of air contaminants of material which cause injury, detriment, nuisance, or annoyance to considerable number of persons or to the public which endanger the comfort, repose, health or safety or which can cause injury or damage to business or property. | CARB |
| California Public Resources Code 25523(a); 20 CCR 1752, 2300 2309 and Div. 2, Chap. 5, Art. 1, Appendix B, Park (k) (CEC and | Requires that CEC’s decision on the AFC include requirements to assure protection of environmental quality; AFC is required to address air quality protection. | CEC |

**Table 2-1**
**Laws, Ordinances, Regulations, and Standards – Air Quality**

| Laws, Ordinances, Regulations, and Standards | Applicability | Administering Agency |
|---|---|---|
| CARB Memorandum of Understanding) | | |
| The California Global Warming Solutions Act of 2006 | Requires new baseload generation power plants to not exceed the rate of greenhouse gas emissions | CARB |
| California Code of Regulation. Title 20, §2902, Greenhouse Gases Emission Performance Standard. | The greenhouse gases emission performance standard (EPS) applicable to this chapter is 1,100 pounds of carbon dioxide per megawatt hour of electricity. | CARB |
| California Code of Regulation. Title 20, §2903, Compliance with the Emission Performance Standard | A power plant's compliance with the EPS shall be determined by dividing the power plant's annual average carbon dioxide emissions in pounds by the power plant's annual average net electricity production in MWh. | CARB |
| California Code of Regulation. Title 20, §2904, Annual Average Carbon Dioxide Emissions | Except as provided in Subsections (b) and (c), a power plant's annual average carbon dioxide emissions are the amount of carbon dioxide produced on an annual average basis by each fuel used in any component directly involved in electricity production, including, but not limited to, the boiler, combustion turbine, reciprocating or other engine, and fuel cell. The fuels used in this calculation shall include, but are not limited to, primary and secondary fuels, backup fuels, and pilot fuels, and the calculation shall assume that all carbon in the fuels is converted to carbon dioxide. Fuels used in ancillary equipment, including, but not limited to, fire pumps, emergency generators, and vehicles shall not be included.<br>(b) [not presented in this report because it pertains to biomass fuels and does not affect the Project]<br>(c) For covered procurements that employ geological formation injection for CO2 sequestration, the annual average carbon dioxide emissions shall not include the carbon dioxide emissions that are projected to be successfully sequestered. The EPS for such power plants shall be determined<br>based on projections of net emissions over the life of the power plant. Carbon dioxide emissions<br>shall be considered successfully sequestered if the sequestration project meets the following requirements:<br>(1) Includes the capture, transportation, and geologic formation injection of CO2 emissions; | CARB |

**Table 2-1**
**Laws, Ordinances, Regulations, and Standards – Air Quality**

| Laws, Ordinances, Regulations, and Standards | Applicability | Administering Agency |
|---|---|---|
| | (2) Complies with all applicable laws and regulations; and<br>(3) Has an economically and technically feasible plan that will result in the permanent sequestration<br>of $CO_2$ once the sequestration project is operational. | |
| **Local** | | |
| SJVAPCD Regulation II, Rule 2201 | This rule shall apply to all new stationary sources and all modifications to existing stationary sources which are subject to the District permit requirements and after construction emit or may emit one or more affected pollutant. The requirements of this rule in effect on the date the application is determined to be complete by the Air Pollution Control Officer (APCO) shall apply to such application except as provided in Section 2.1. | SJVAPCD |

**Table 2-1**
**Laws, Ordinances, Regulations, and Standards – Air Quality**

| Laws, Ordinances, Regulations, and Standards | Applicability | Administering Agency |
|---|---|---|
| SJVAPCD Regulation II, Rule 2520 | The purpose of this rule is to provide for the following:<br>1.1 An administrative mechanism for issuing operating permits for new and modified sources of air contaminants in accordance with requirements of 40 Code of Federal Regulations (CFR) Part 70.<br>1.2 An administrative mechanism for issuing renewed operating permits for sources air contaminants in accordance with requirements of 40 CFR Part 70.<br>1.3 An administrative mechanism for revising, reopening, revoking, and terminating operating permits for sources of air contaminants in accordance with requirements of 40 CFR Part 70.<br>1.4 An administrative mechanism for incorporating requirements authorized preconstruction permits issued under District Rule 2201 (New and Modified Stationary Source Review) in a Part 70 permit as administrative amendments, provided that such permits meet procedural requirements substantially equivalent the requirements of 40 CFR 70.7 and 70.8, and compliance requirements substantially equivalent to those contained in 40 CFR 70.6.<br>1.5 The applicable federal and local requirements to appear on a single permit. | SJVAPCD |
| SJVAPCD Regulation II, Rule 2540 | All stationary sources subject to Part 72, Title 40, CFR | SJVAPCD |
| SJVAPCD Regulation II, Rule 2550 | The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after 28 June 1998. Requirements for other projects that result in increases in emissions of hazardous air pollutants are addressed in the District's Risk Management Policy for Permitting New and Modified Sources. | SJVAPCD |
| SJVAPCD Regulation III | Identifies fees that are applicable to permit modifications, new facilities, and permitted emissions | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4001 | All new sources of air pollution and modification of existing sources of air pollution shall comply with the standards, criteria, and requirements set forth therein. | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4002 | This rule incorporates the National Emission Standards for Hazardous Air Pollutants from Part 61, Chapter I, Subchapter C, Title 40, CFR and the National Emission Standards for Hazardous Air Pollutants for Source Categories from Part 63, Chapter I, Subchapter C, Title 40, CFR. | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4101 | The provisions of this rule shall apply to any source operation which emits or may emit air contaminants. | SJVAPCD |

**Table 2-1**
**Laws, Ordinances, Regulations, and Standards – Air Quality**

| Laws, Ordinances, Regulations, and Standards | Applicability | Administering Agency |
|---|---|---|
| SJVAPCD Regulation IV, Rule 4102 | This rule shall apply to any source operation which emits or may emit air contaminants or other materials. | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4201 | Particulate Matter Concentration<br>0.1 grains/scf of gas at dry standard conditions. | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4202 | Particulate Matter Emission - this rule provides a table of emission rates in lbs/hr, based on process feed rates. | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4301 | The purpose of this rule is to limit the emission of air contaminants from fuel burning equipment. This rule limits the concentration of combustion contaminants and specifies maximum emission rates for sulfur dioxide, nitrogen oxides and combustion contaminant emissions. | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4304 | The purpose of this rule is to provide an equipment tuning procedure for boilers, steam generators and process heaters to control visible emissions and emissions of both nitrogen oxides (NOx) and carbon monoxide (CO). | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4305-4308 | The purpose of this rule is to limit emissions of $NO_x$ and CO from boilers, steam generators, and process heaters. | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4311 | Potential conflicts with SJVAPCD flaring regulations | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4701 | Except as provided in Section 4.0, the provisions of this rule apply to any internal combustion engine, rated greater than 50 brake horsepower (bhp) that requires a Permit to Operate (PTO). | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4702 | This rule applies to any internal combustion engine with a rating of greater than 50 bhp. | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4703 | Stationary Gas Turbines - will affect $NO_x$ and CO emissions. | SJVAPCD |
| SJVAPCD Regulation IV, Rule 4801 | Sulfur Compounds - 0.2 % by volume calculated as SO2 | SJVAPCD |
| SJVAPCD Regulation VIII | The purpose of Regulation VIII (Fugitive PM10 Prohibitions) is to reduce ambient concentrations of fine particulate matter (PM10) by requiring actions to prevent, reduce or mitigate anthropogenic fugitive dust emissions. The Rules contained in this Regulation have been developed pursuant to U.S. Environmental Protection Agency guidance for Serious PM10 Nonattainment Areas. The rules are applicable to specified anthropogenic fugitive dust sources. Fugitive dust contains PM10 and particles larger than PM10. Controlling fugitive dust emissions when visible emissions are detected will not prevent all | SJVAPCD |

**Table 2-1**
**Laws, Ordinances, Regulations, and Standards – Air Quality**

| Laws, Ordinances, Regulations, and Standards | Applicability | Administering Agency |
|---|---|---|
| | PM10 emissions, but will substantially reduce PM10 emissions. | |
| SJVAPCD Regulation IX | This Rule specifies the criteria and procedures for determining the conformity of federal actions with the SJVAPCD's air quality implementation plan. | SJVAPCD |
| **Industry** | | |
| None Applicable | None Applicable | |

**Notes:**
bhp = brake horsepower
CAA = Clean Air Act (federal)
CAAQS = California Ambient Air Quality Standard
CARB = California Air Resources Board
CEC = California Energy Commission
CFR = Code of Federal Regulations
CO = Carbon monoxide
NAAQS = National Ambient Air Quality Standard
$NO_X$ = Nitrous Oxide
$PM_{10}$ = particulate matter
SJVAPCD = San Joaquin Valley Air Pollution Control District
$SO_2$ = Sulfur dioxide

## 2.1 AMBIENT AIR QUALITY STANDARDS

The EPA, in response to the federal CAA of 1970, established NAAQS in Title 40 CFR Part 50. The NAAQS include both primary and secondary standards for six "criteria" pollutants. These criteria pollutants are ozone ($O_3$), carbon monoxide (CO), nitrogen dioxide ($NO_2$), sulfur dioxide ($SO_2$), particulate matter ($PM_{10}$), and lead (Pb). Primary standards were established to protect human health, and secondary standards were designed to protect property and natural ecosystems from the effects of air pollution.

The 1990 CAAA established attainment deadlines for all designated areas that were not in attainment with the NAAQS. In addition to the NAAQS described above, a new federal standard for fine particulate matter ($PM_{2.5}$) and a revised $O_3$ standard were promulgated in July 1997. The new federal standards were challenged in a court case during 1998. The court required revisions in both standards before EPA could enforce them. The U.S. Supreme Court upheld an appeal of the District Court decision in February 2001. These issues were resolved and the 1-hour $O_3$ standard revoked in 2005 while the revised $PM_{2.5}$ standard was made effective in 2006. The state of California has adopted CAAQS that are in some cases more stringent than the NAAQS. The NAAQS and CAAQS relevant to the Project are summarized in Table 2-2, Relevant Ambient Air Quality Standards.

EPA, CARB, and the local air pollution control districts determine air quality attainment status by comparing local ambient air quality measurements from the state or local ambient air monitoring stations with the NAAQS and CAAQS. Those areas that meet ambient air quality standards are classified as "attainment" areas; areas that do not meet the standards are classified as "non-attainment" areas. Areas that have insufficient air quality data may be identified as unclassifiable areas. These attainment designations are determined on a pollutant-by-pollutant basis. The area around the Project Site is classified as attainment with respect to the NAAQS for $NO_2$, $PM_{10}$, CO, and $SO_2$, and non-attainment for $O_3$ and $PM_{2.5}$. With respect to CAAQS, the area around the Project Site is classified as attainment for $NO_2$, CO, sulfates, Pb, hydrogen sulfide ($H_2S$), and $SO_2$, and non-attainment for $O_3$, $PM_{10}$, and $PM_{2.5}$. Nitrogen dioxide and $SO_2$ are regulated as $PM_{10}$ precursors, and $NO_2$ and volatile organic compounds (VOCs) as $O_3$ precursors. Table 2-3 , Attainment Status for Kern County with Respect to Federal and California Ambient Air Quality Standards, presents the attainment status (both federal and state) for the San Joaquin Valley Air Basin (SJVAB).

As mentioned above, both EPA and CARB are involved with air quality management in the San Joaquin Air Basin (SJVAB) area along with the SJVAPCD.

**Table 2-2**
**Relevant Ambient Air Quality Standards**

| Pollutant | Averaging Time | NAAQS[1] | | CAAQS[2] |
|---|---|---|---|---|
| | | Primary[3,4] | Secondary[3,5] | Concentration[3] |
| Ozone ($O_3$) | 1-Hour | Revoked [8] | Same as Primary Standard | 0.09 ppm (180 µg/m$^3$) |
| | 8-Hour | 0.075 ppm | | 0.07 ppm (137 µg/m$^3$) |
| Carbon Monoxide (CO) | 8-Hour | 9 ppm (10 mg/m$^3$) | None | 9.0 ppm (10 mg/m$^3$) |
| | 1-Hour | 35 ppm (40 mg/m$^3$) | | 20 ppm (23 mg/m$^3$) |
| Nitrogen Dioxide ($NO_2$)[9] | Annual Average | 0.053 ppm (100 µg/m$^3$) | Same as Primary | 0.030 ppm (57 µg/m$^3$) |

## Table 2-2
## Relevant Ambient Air Quality Standards

| Pollutant | Averaging Time | NAAQS[1] | | CAAQS[2] |
|---|---|---|---|---|
| | | Primary[3,4] | Secondary[3,5] | Concentration[3] |
| | 1-Hour | - | Standard | 0.18 ppm (339 $\mu g/m^3$) |
| Sulfur Dioxide ($SO_2$) | Annual Average | 0.03 ppm (80 $\mu g/m^3$) | - | - |
| | 24-Hour | 0.14 ppm (365 $\mu g/m^3$) | - | 0.04 ppm (105 $\mu g/m^3$) |
| | 3-Hour | - | 0.5 ppm (1,300 $\mu g/m^3$) | - |
| | 1-Hour | - | - | 0.25 ppm (655 $\mu g/m^3$) |
| Suspended Particulate Matter ($PM_{10}$) | 24-Hour | 150 $\mu g/m^3$ | Same as Primary Standard | 50 $\mu g/m^3$ |
| | Annual Arithmetic Mean | Revoked [6] | | 20 $\mu g/m^3$ |
| Fine Particulate Matter ($PM_{2.5}$)[7] | 24-Hour | 35 $\mu g/m^3$ | Same as Primary Standard | - |
| | Annual Arithmetic Mean | 15 $\mu g/m^3$ | | 12 $\mu g/m^3$ |
| Lead (Pb) | 30-Day Average | - | - | 1.5 $\mu g/m^3$ |
| | Quarterly Average | 1.5 $\mu g/m^3$ | Same as Primary Standard | - |
| Hydrogen Sulfide ($H_2S$) | 1-Hour | No Federal Standards | | 0.03 ppm (42 $\mu g/m^3$) |
| Sulfates ($SO_4$) | 24-Hour | | | 25 $\mu g/m^3$ |
| Visibility Reducing Particles | 8-Hour (10 am to 6 pm, Pacific Standard Time) | | | In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent. |

Source: CARB. 2009. (http://www.arb.ca.gov/aqs/aaqs2.pdf)

**Notes:**

1. National standards (other than ozone, particulate matter, and those based on annual averages or annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth highest 8-hour concentration in a year, averaged over 3 years, is equal to or less than the standard. For $PM_{10}$, the 24-hour standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 $\mu g/m^3$ is equal to or less than one. For $PM_{2.5}$, the 24-hour standard is attained when 98 percent of the daily concentrations, averaged over 3 years, are equal to or less than the standard. Contact USEPA for further clarification and current federal policies.
2. California standards for ozone, carbon monoxide (except Lake Tahoe), sulfur dioxide (1 and 24 hour), nitrogen dioxide, suspended particulate matter—$PM_{10}$, $PM_{2.5}$, and visibility-reducing particles, are values that are not to be exceeded. All others are not to be equaled or exceeded. California ambient air quality standards are listed in the Table of Standards in § 70200 of Title 17 of the California Code of Regulations.
3. Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25°C and a reference pressure of 760 torr. Most measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 torr; ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.
4. National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health.
5. National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.
6. Due to a lack of evidence linking health problems to long-term exposure to coarse particle pollution, the agency revoked the annual $PM_{10}$ standard in 2006 (effective 17 December 2006).
7. To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 $\mu g/m^3$ (effective 17 December 2006)
8. On 15 June 2005, the 1-hour ozone standard (0.12 ppm) was revoked for all areas except the 8-hour ozone nonattainment Early Action Compact Areas (EAC) areas.

$\mu g/m^3$ = micrograms per cubic meter    NAAQS = National Ambient Air Quality Standards

**Table 2-2**
**Relevant Ambient Air Quality Standards**

| Pollutant | Averaging Time | NAAQS[1] | | CAAQS[2] |
|---|---|---|---|---|
| | | Primary[3,4] | Secondary[3,5] | Concentration[3] |

CAAQS = California Ambient Air Quality Standards ppm = parts per million [3]
$mg/m^3$ = milligram per cubic meter

**Table 2-3**
**Attainment Status for Kern County with Respect to**
**Federal and California Ambient Air Quality Standards**

| Pollutant | Federal Attainment Status | State Attainment Status |
|---|---|---|
| Ozone | Non-attainment | Non-attainment |
| CO | Attainment | Attainment |
| $NO_2$ | Attainment | Attainment |
| $SO_2$ | Attainment | Attainment |
| $PM_{10}$ | Attainment[1] | Non-attainment |
| $PM_{2.5}$ | Non-attainment | Non-attainment |
| Lead | Unclassified | Attainment |

Source: CARB-CAAQS (http://www.arb.ca.gov/aqs/aaqs2.pdf)

**Notes:**

1 = On September 25, 2008, EPA redesignated the San Joaquin Valley to attainment for the PM10 National Ambient Air Quality Standard (NAAQS) and approved the PM10 Maintenance Plan.

CO = carbon monoxide
$NO_2$ = nitrogen dioxide
$PM_{10}$ = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
$SO_2$ = sulfur dioxide

## 2.2 PREVENTION OF SIGNIFICANT DETERIORATION

The federal prevention of significant deterioration (PSD) program has been established to protect deterioration of air quality in those areas that already meet NAAQS. The PSD program specifies allowable concentration increases for attainment pollutants due to new emission sources. These increases allow economic growth while preserving the existing air quality, protecting public health and welfare, and protecting Class I areas (national parks and wilderness areas). The PSD regulations require major stationary sources to undergo a pre-construction review that includes an analysis and implementation of BACT, a PSD increment consumption analysis, an ambient air quality impact analysis, and analysis of AQRVs (impacts on visibility). The Project is subject to these requirements.

The PSD applicability triggers for CO, $SO_2$, $NO_X$, $PM_{10}$, VOCs, and Pb are as shown in Table 2-4, PSD Emission Threshold Triggers for New Stationary Sources. For Project emissions of CO, $NO_X$, and $PM_{10}$ above these PSD triggers, the Applicant must demonstrate through modeling that such emissions will not interfere with the attainment or maintenance of the applicable NAAQS and will not cause an exceedance of the applicable PSD increments shown in Table 2-5, Prevention of Significant Deterioration Allowable Increments (in micrograms per cubic meter [μg/m$^3$]). For all Project emissions, the Applicant must demonstrate through modeling that the increase in emissions will not interfere with the attainment or maintenance of the NAAQS.

**Table 2-4**
**PSD Emission Threshold Triggers for New Stationary Sources**

| Pollutant | Applicability Thresholds (tpy) | Project Emissions (tpy) | PSD Triggered by Project? |
|---|---|---|---|
| CO | 100 | 350 | Yes |
| $SO_2$ | 100 | 42.2 | No |
| $NO_X$ | 100 | 204 | Yes |
| $PM_{10}$ | 100 | 141 | Yes |
| VOCs | 100 | 32.5 | No |
| Pb | 0.6 | <0.6 | No |

Source: 40 CFR § 52.21 and HECA Project.

**Notes:**

Project emissions include all emissions from natural gas.

CO = carbon monoxide
$NO_x$ = nitrogen dioxide
Pb = lead
$PM_{10}$ = particulate matter less than 10 microns in diameter
$SO_2$ = sulfur dioxide
VOC = volatile organic compound

**Table 2-5**
**Prevention of Significant Deterioration Allowable Increments**
**(μg/m$^3$)**

| Standard | Class I Area | Class II Area | Class III Area |
|---|---|---|---|
| $PM_{10}$ Annual Arithmetic Mean | 4 | 17 | 34 |
| $PM_{10}$ 24-Hour Maximum | 8 | 30 | 60 |
| $SO_2$ Annual Arithmetic Mean | 2 | 20 | 40 |
| $SO_2$ 24-Hour Maximum | 5 | 91 | 182 |
| $SO_2$ 3-Hour Maximum | 25 | 512 | 700 |
| $NO_2$ Annual Arithmetic Mean | 2.5 | 25 | 50 |

Source: 40 CFR § 52.21.

μg/m$^3$ = micrograms per cubic meter
$NO_2$ = nitrogen dioxide
$PM_{10}$ = particulate matter less than 10 microns in diameter
$SO_2$ = sulfur dioxide

## 2.3 ACID RAIN PROGRAM REQUIREMENTS

Title IV of the CAAA applies to sources of air pollutants that contribute to acid rain formation, including certain sources of $SO_2$ and $NO_x$ emissions. Title IV is implemented by USEPA under

40 CFR 72, 73, and 75. The SJVAPCD has been delegated the authority by EPA to administer Title IV requirements under its Title V Operating Permit program in Regulation II. The Acid Rain Program provisions of 40 CFR Part 72, Subparts A through I are incorporated in SJVAPCD Rule 2540. Allowances of $SO_2$ emissions are set aside in 40 CFR 73. Sources subject to Title IV are required to obtain $SO_2$ allowances, to monitor their emissions, and obtain $SO_2$ allowances when a new source is permitted. Sources such as the Project that utilize fossil-derived fuel are required to comply with the acid rain program requirements. Under this program, the Applicant is subject to the following requirements:

- Submittal of an Acid Rain permit application
- Remain in compliance with $SO_2$ and $NO_x$ limitations/allowances
- Preparation and maintenance of an Acid Rain Compliance Plan
- Installation and maintenance of emission monitoring system

The Project is a new facility, and therefore, an Acid Rain Permit application will be submitted to SJVAPCD at least 24 months before the date of initial operation of the unit.

To meet the $NO_x$ and $SO_2$ requirements, the Project must estimate $SO_2$ and carbon dioxide emissions, and monitor $NO_x$ emissions with certified CEMS.

## 2.4 NEW SOURCE PERFORMANCE STANDARDS

New Source Performance Standards (NSPS) have been established by USEPA to limit air pollutant emissions from certain types of new and modified stationary sources. The NSPS regulations are contained in 40 CFR Part 60 and cover nearly 70 source categories. CTG/HRSG is regulated under Subpart Da.

In general, local emission limitation rules or BACT requirements are more restrictive than the NSPS requirements. A case-by-case applicability of NSPS regulations for the sources is further discussed in the BACT analysis document (Appendix A).

## 2.5 FEDERALLY MANDATED OPERATING PERMITS

Title V of the CAAA requires EPA to develop a federal operating permit program that is implemented under 40 CFR Part 70. This program is administered by SJVAPCD under Regulation II, Rule 2520. Each major source, Phase II acid rain facility, and other source types designated by USEPA must obtain a Part 70 permit. Permits must contain emission estimates based on potential-to-emit, identification of all emission sources and controls, a compliance plan, and a statement indicating each source’s compliance status. The permits must also incorporate all applicable federal, state, or SJVAPCD orders, rules and regulations.

Because the Project will constitute a new stationary source, the Applicant will submit a complete Title V permit application for a Title V permit to operate within 12 months after Power Block startup.

## 2.6 CALIFORNIA POWER PLANTS SITING REQUIREMENTS

Under its approved certified regulatory program, which is a CEQA equivalent program, CEC has been charged with assessing the environmental impacts of each new power plant and considering the implementation of feasible mitigation measures to prevent potential significant impacts. CEQA Guidelines (Title 14, California Administrative Code, §15002(a)(3)) state that the basic purpose of CEQA is to "prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible."

CEC's siting regulations require that, except under certain conditions, a new power plant can only be approved if the project complies with all federal, state, and local air quality rules, regulations, standards, guidelines, and ordinances that govern the construction and operation of the project. A project must demonstrate that project emissions will be appropriately controlled to mitigate significant impacts from the project and that it will not jeopardize attainment and maintenance of the ambient air quality standards. Cumulative impacts, impacts due to pollutant interaction, and impacts from non-criteria pollutants must also be considered.

## 2.7 AIR TOXICS "HOT SPOTS" PROGRAM

As required by the California Health and Safety Code §44300, all facilities with criteria air pollutant emissions in excess of 10 tons per year are required to submit air toxic "Hot Spots" emissions information. The Project will be required to provide quantitative information to SJVAPCD on the Project's emissions of toxic air contaminants. This requirement is applicable only after the start of operation.

## 2.8 DETERMINATION OF COMPLIANCE, AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Under Regulation II, Rule 2010, 2070, and 2201, SJVAPCD administers the air quality regulatory program for the construction, alteration, replacement, and operation of new power plants. As part of the AFC process, the Project will be required to obtain a pre-construction Determination of Compliance (DOC) from the SJVAPCD. Regulation II, Rule 2201 incorporates other SJVAPCD rules that pertain to sources that may emit air contaminants through the issuance of air permits (i.e., Authority to Construct [ATC] and Permit to Operate [PTO]). This permitting process allows the SJVAPCD to adequately review new and modified air pollution sources to ensure compliance with all applicable prohibitory rules and to ensure that appropriate emission controls are used. An ATC allows for the construction of the air pollution source and remains in effect until the PTO application is granted, denied, or cancelled. Projects that are reviewed under the CEC application process must obtain an ATC from the local air district (in this case, SJVAPCD) prior to construction of the new power plant. For power plants under the siting jurisdiction of the CEC, the SJVAPCD issues a DOC in lieu of an ATC. The DOC is incorporated into the CEC license. The ATC remains in effect until the PTO application is granted, denied, or cancelled. Once the Project commences operations and demonstrates compliance with the DOC, SJVAPCD will issue a PTO. The PTO specifies conditions that the air pollution source must meet to comply with other air quality standards and will incorporate applicable DOC requirements. An application for the DOC will be submitted to the SJVAPCD simultaneously with the filing of the Revised AFC.

## 2.9 SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT REQUIREMENTS

The SJVAPCD has been delegated responsibility for implementing the federal, state, and local regulations on air quality in Kern County to achieve and maintain both state and federal air quality standards; implementing permit programs established for the construction, modification, and operation of sources of air pollution; enforcing air pollution statutes, regulations and prohibitory rules governing non-vehicular sources; and developing programs to reduce emissions from indirect sources. The Project is subject to SJVAPCD regulations that apply to new sources of emissions, to the prohibitory regulations that specify emissions standards, and to the requirements for evaluation of air pollutant impacts for both criteria and toxic air pollutants. The following sections include the evaluation of the Project’s compliance with the applicable SJVAPCD requirements.

## 2.10 RULES AND REGULATIONS

### *Rule 1080, Stack Monitoring*

Outlines facility requirements for continuous monitoring equipment from any facility emitting pollutants for which emission limits have been established. The Project will be constructed and operated to comply with the requirements of Rule 1080.

### *Rule 1081, Source Sampling*

Outlines facility design requirements for source sampling from any facility emitting pollutants for which emission limits have been established. The Project will be constructed and operated to comply with the requirements of Rule 1081.

### *Rule 1100, Equipment Breakdown*

This rule details the notification and corrective action requirements necessary in an equipment breakdown situation. As operator of the Project, the Applicant will comply with these requirements.

### *Rule 2010, Permits Required*

An ATC and PTO will be required for the Project. The Applicant will submit the required application materials for these permits to SJVAPCD.

### *Rule 2201, New and Modified Stationary Source Review*

This rule outlines the emission standards, the offset requirements and conditions, the required demonstrations that the new source or modification will not cause or contribute to violations of the ambient air quality standards, procedures for power plants under the CEC process, methods for calculating project emissions, and required air quality analysis procedures. Compliance with the specific provisions of this rule is discussed below.

**BACT.** An Applicant must apply BACT to any new or modified emissions unit that has a potential to emit 2.0 pounds per day or more of any pollutant. The SJVAPCD maintains a list of current BACT standards for specific source categories, which is posted on the District's website. Appendix A provides a formal BACT evaluation for the Project. The proposed BACT levels for the Project turbines are shown in Table 2-6, Proposed BACT for the Project.

**Table 2-6**
**Proposed BACT for the Project**

| Pollutant | Technology | Emission Limit |
|---|---|---|
| **CTG/HRSG Combustion Turbine (excluding Start up/Shutdown conditions)** | | |
| NOx | Diluent Injection, Selective Catalytic Reduction | 4 ppm $NO_x$ @ 15% $O_2$ on hydrogen-rich fuel and natural gas fuel, 3-hour average |
| CO | Good Combustion Practice (GCP), CO Catalyst | 3 ppm CO @ 15% $O_2$ on hydrogen-rich fuel, 5 ppm CO @ 15% $O_2$ on natural gas fuel |
| $PM/PM_{10}$ | GCP, Gas Cleanup, Gaseous Fuels | 24 lb/hr on hydrogen-rich fuel, 18 lb/hr on natural gas fuel |
| $SO_2$ | Hydrogen-rich Gas cleanup, pipeline quality natural gas | ≤ 5 ppmv in undiluted total sulfur (hydrogen-rich syngas) ≤ 0.75 grain / 100 SCF (12.65 ppm for natural gas) |
| VOC | CO Catalyst | 1 ppm VOC @ 15% $O_2$ on hydrogen-rich fuel, 2 ppm VOC @ 15% $O_2$ on natural gas fuel |
| $NH_3$ | Selective Catalytic Reduction | 5 ppm $NH_3$ slip on hydrogen-rich fuel and natural gas fuel |
| **Auxiliary CTG (excluding Start up/Shutdown conditions) Natural Gas fired.103.3 MW** | | |
| NOx | Diluent Injection, Selective Catalytic Reduction | 2.5 ppm $NO_x$ @ 15% $O_2$ on natural gas fuel, 3-hour average |
| CO | CO Catalyst | 6.0 ppm CO @ 15% $O_2$ |
| $PM/PM_{10}$ | PUC regulated natural gas | 6 lb/hr on natural gas fuel |
| $SO_2$ | | ≤ 0.75 grain / 100 SCF (12.65 ppm for natural gas) |
| VOC | CO Catalyst | 2 ppm VOC @ 15% $O_2$ on natural gas fuel |
| $NH_3$ | Selective Catalytic Reduction | 10 ppm $NH_3$ slip on natural gas fuel |
| **Cooling Towers** | | |
| $PM/PM_{10}$ | High Efficiency Drift Eliminators, TDS limit in circulating water, and Good Operating Practice | 0.0005% drift as percent of the circulating water |
| **Auxiliary Boiler, Natural Gas 142 MMBtu/hr** | | |
| NOx | Low $NO_x$ Burner with FGR | 9 ppm $NO_x$ @ 3% $O_2$ on natural gas fuel |
| CO | GCP | 50 ppmvd @ 3% $O_2$ |
| $PM/PM_{10}$ | GCP, PUC grade natural gas fuel | 0.005 lb/MMBtu heat input |
| $SO_2$ | | ≤ 0.75 grain / 100 SCF (12.65 ppm for natural gas) |
| VOC | | 0.004 lb/MMBtu heat input |
| **Emergency Diesel Engines (2 Emergency Generators )** | | |
| NOx | Combustion controls, restricted operating hours | 0.5 g/brake horsepower (bhp)/hr |
| CO | | 0.29 g/bhp/hr |
| $PM/PM_{10}$ | Combustion controls, Low Sulfur Diesel fuel, restricted operating hours | 0.03 g/bhp/hr |
| $SO_2$ | | N/A |
| VOC | | 0.11 g/bhp/hr |

**Table 2-6**
**Proposed BACT for the Project**

| Pollutant | Technology | Emission Limit |
|---|---|---|
| **Emergency Diesel Engines (Fire Pump)** | | |
| NOx | Combustion controls, restricted operating hours | 1.5 g/bhp/hr |
| CO | | 2.60 g/bhp/hr |
| $PM/PM_{10}$ | Combustion controls, Low Sulfur Diesel fuel, restricted operating hours | 0.015 g/bhp/hr |
| $SO_2$ | | N/A |
| VOC | | 0.14 g/bhp/hr |
| **Gasification Flare** | | |
| NOx, CO, $PM/PM_{10}$, $SO_2$, VOC | GCP, gaseous fuel only, Gas cleanup/Limit on reduced sulfur in syngas | |
| **Thermal Oxidizer (Sulfur Recovery System)** | | |
| NOx | GCP | 4.8 lb/hr 24-hour average |
| CO | | 4.0 lb/hr, 1-hour average |
| $PM/PM_{10}$ | | 0.16 lb/hr 24-hour average |
| $SO_2$ | GCP, Gas cleanup | 2.02 lb/hr, 3-hour average |
| VOC | GCP | 32.84 lb/hr, annual average |
| **SRU Flare with natural gas assist (Sulfur Recovery System)** | | |
| $NO_x$ | GCP | |
| CO | | |
| $PM/PM_{10}$ | GCP, gaseous fuel only | |
| $SO_2$ | GCP, Caustic Scrubber | |
| VOC | GCP | |
| **$CO_2$ Vent** | | |
| CO | Gas Cleanup | 1,000 ppmv |
| VOC | Gas Cleanup | 40 ppmv |
| **Gasifier Warming (refractory heater)** | | |
| NOx | GCP | 0.11 lb/MMBtu, higher heating value (HHV) |
| CO | GCP | 0.09 lb/MMBtu, HHV |
| $PM/PM_{10}$ | GCP, gaseous fuel only | 0.008 lb/MMBtu, HHV |
| $SO_2$ | GCP, PUC grade Natural gas | 0.002 lb/MMBtu, HHV (12.65 ppm) |
| VOC | GCP | 0.007 lb/MMBtu, HHV |
| **Feedstock** | | |
| $PM/PM_{10}$ | Dust Collector | 0.005 grain/scf outlet dust loading |

Source: HECA Project

**Notes:**

BACT = best available control technology
CO = carbon monoxide
CPUC = California Public Utility Commission
CTG = combustion turbine generator
FGR = flue gas recirculation
MMBtu = million British thermal units
NOx = nitrogen dioxide
$O_2$ = oxygen
$PM/PM_{10}$ = particulate matter/particulate matter less than 10 microns
ppm = parts per million
ppmvd = parts per million volumetric dry
SCF = standard cubic feet
$SO_2$ = sulfur dioxide
VOC = volatile organic compound

**Section 4.5, Emissions Offset Requirements.** This section of Rule 2201 requires that offsets be provided for a new stationary source with a potential to emit equal to or exceeding the established levels.

**Section 4.14, Ambient Air Quality Standards.** Emissions from a new or modified Stationary Source may not cause or make worse the violation of an AAQS. Modeling used for the purposes of demonstrating compliance with this rule must be consistent with the requirements contained in the most recent edition of USEPA's *Guidelines on Air Quality Models*, unless the Air Pollution Control Officer finds that such model is inappropriate for use. After making such a finding, the Air Pollution Control Officer may designate an alternate model only after allowing for public comments and only with the concurrence of CARB or the USEPA.

As described in Section 6.7, Compliance with Ambient Air Quality Standards, an air quality modeling analysis has been conducted to demonstrate that the Project will not cause or make worse the violation of any air quality standard.

**Section 5.8, Power Plants.** This section applies to all power plants proposed to be constructed in the SJVAPCD and for which a Notice of Intention or AFC has been accepted by the CEC. It describes the actions to be taken by SJVAPCD to provide information to CEC and CARB to ensure that the Project will conform to the District's rules and regulations. After the application has been submitted to CEC and other responsible agencies, including SJVAPCD, the Air Pollution Control Officer is required to conduct a DOC review. This determination consists of a review identical to that which would be performed if an application for an ATC had been received for the power plant. If the information contained in the AFC does not meet the requirements of this regulation, then the Air Pollution Control Officer is required to so inform the CEC within 20 calendar days following receipt of the AFC. In such an instance, the AFC is considered to be incomplete and returned to the Applicant for re-submittal.

**Section 6.0, Certification of Conformity.** This section describes how a new or modified source that is subject to the requirements of Rule 2520 may choose to apply for a certificate of conformity with the procedural requirements of 40 CFR Part 70 for a Federal Operating Permit. A certificate of conformity will allow changes authorized by the ATC permit to be incorporated in the Part 70 permit as administrative permit amendments.

### *Rule 2520, Federally Mandated Operating Permits*

Provides an administrative mechanism for issuing operating permits for new and modified sources of air contamination accordance with the federal requirements of 40 CFR Part 70. Under this rule, the Project will be required to obtain an operating permit, because it will include emission units that are subject to recently promulgated NSPS and because it will also require an acid rain permit.

### *Rule 3010/3020, Permit Fees*

This rule and the fee schedules in rule 3020 establish the filing and permit review fees for specific types of new sources, as well as annual renewal fees and penalty fees for existing sources.

### Rule 3110, Air Toxics Fees

This rule applies to facilities subject to the requirements of the Air Toxics "Hot Spots" Information and Assessment Act (§§ 44340 and 44383 of the California Health and Safety Code) and to facilities subject to National Emission Standards for Hazardous Air Pollutants (NESHAPs) issued pursuant to §112 of the federal CAA.

### Rule 3135, Dust Control Plan Fee

This rule recovers the District's cost for reviewing Dust Control Plans and conducting site inspections to verify compliance with such plans.

### Rule 3170, Federally Mandated Ozone Non-attainment Fee

The purpose of this rule is to satisfy requirements specified in §185 and §1 82(f) of the CAA. This rule applies to major sources of $NO_x$ and VOC. The fees required pursuant to this section are additional to the permit fees and other fees required under other Rules and Regulations. This rule will cease to be effective when the Administrator of USEPA designates the SJVAPCD to be in attainment of the federal 1-hour standard for $O_3$. The Project will be a major source under either the federal or SJVAPCD definitions and is subject to Rule 3170.

### Rule 4001, New Source Performance Standards

This rule incorporates the federal NSPS from 40 CFR Part 60.

### Rule 4002, National Emission Standards for Hazardous Air Pollutants

This rule incorporates the federal NESHAPs from Part 61 and Part 63, Chapter I, Subchapter C, Title 40 CFR.

### Rule 4101, Visible Emissions

This rule applies to the opacity of discharges from any single source. Emissions from the sources of the Project will be below threshold opacity levels described in this rule.

### Rule 4102, Nuisance

This rule states that there shall be no discharge of such quantities of any pollutant or material which could cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public or which cause or have a natural tendency to cause injury or damage to business or property.

### Rule 4201, Particulate Matter Concentration

This rule applies to the discharge of particulate matter into the atmosphere. The relevant limit for the Project is expressed in Rule 4201, which states that no person shall release or discharge into the atmosphere from any single source operation dust, fumes, or total suspended particulate matter, in excess of 0.1 grains per dry standard cubic foot of natural gas as determined by following test methods: Particulate matter concentration – USEPA Method 5; Stack gas velocity – USEPA Method 2; Stack gas moisture – USEPA Method 4. The Project natural gas turbines will easily comply with this requirement, with a maximum $PM_{10}$ emission rate of approximately 0.045 grains per dry standard foot of natural gas consumption.

### Rule 4301, Fuel-burning Equipment

This rule limits the emission levels of $NO_x$, $SO_2$, and fuel combustion contaminants (particulates) from any fuel burning equipment unit. The specific limits are 140 pounds per hour of $NO_x$, calculated as $NO_2$, 200 pounds per hour of $SO_2$, 0.1 grains per cubic foot of gas calculated to 12 percent of carbon dioxide at dry standard conditions, and 10 pounds per hour of combustion contaminants.

### Rule 4703, Stationary Gas Turbines

This rule limits the $NO_x$ and CO emissions from gas turbines with ratings greater than 0.3 MW. $NO_x$ emissions concentrations shall be averaged over a 3-hour period using consecutive 15-minute sampling periods, or if CEMS are used, all applicable requirements of 40 CFR Part 60 must be met.

### Rule 4801 – Sulfur Compounds

This rule limits the emissions of sulfur compounds to less than 0.2 percent by volume on a dry basis averaged over 15 consecutive minutes by using USEPA Method 8 and CARB Method 1-100.

### Rule 8021, Construction, Demolition, Excavation, Extraction, and Other Earthmoving Activities

This rule limits fugitive dust emissions from construction, demolition, excavation, extraction, and other earthmoving activities such that opacity levels are kept to no more than 20 percent.

### Rule 8041, Carryout and Trackout

This rule requires the limiting of carryout and trackout dust emissions from sites is applicable to construction of the Project.

### Rule 8051, Open Areas

This rule applies to any open area of 3.0 acres or more in rural areas with at least 1,000 square feet of disturbed surface area. Dust emissions must be kept below 20 percent opacity.

### Rule 8061, Paved and Unpaved Roads

This rule limits the emission of fugitive dust from roads to no more than 20 percent opacity through different control measures. Depending on traffic levels, the road must meet certain width requirements.

### Rule 8071, Unpaved Vehicle/Equipment Traffic Areas

This rule limits the emission of fugitive dust to no more than 20 percent opacity through different control measures.

## 2.11 PERMITTING/PROJECT COORDINATION

The ATC permitting process that would otherwise apply is superseded in the case of CEC power plant licensing projects by the DOC process, which is its functional equivalent. The CEC's final decision on this Revised AFC will serve as the principal approval required to ensure that the Project's impacts to air quality would be within acceptable levels. However, a PTO would be awarded following SJVAPCD confirmation that the Project has been constructed to operate as described in the permit applications. The SJVACPD review and approval process is expected to occur on a schedule within the overall CEC AFC review process.

EPA will require this PSD permit be in place prior to the start of some elements of the construction. The EPA review and approval process is expected to occur on a schedule within the overall CEC AFC review process.

## 3.1 CLIMATOLOGY

The California Air Resources Board (CARB) has divided California into regional air basins according to topographic drainage features. The Project Site is located near the unincorporated community of Tupman, Kern County within the jurisdiction of the San Joaquin Valley Air Basin (SJVAB).

SJVAB, which is approximately 250 miles long and 35 miles wide, is the second largest air basin in the state. Air pollution, especially the dispersion of air pollutants, is directly related to a region's topographic features. The SJVAB is defined by the Sierra Nevada Mountains in the east (8,000 to 14,000 feet in elevation), the Coast Range in the west (averaging 3,000 feet in elevation), and the Tehachapi Mountains in the south (6,000 to 8,000 feet in elevation). The valley opens to the sea at the Carquinez Strait where the San Joaquin-Sacramento Delta empties into San Francisco Bay.

The SJVAB has an inland Mediterranean climate, averaging more than 260 sunny days per year. The valley floor is characterized by warm, dry summers and cooler winters. Long-term average temperature and precipitation data have been collected at Buttonwillow, the surface meteorological station nearest to the Project Site, and are presented in Table 3-1, Temperature and Precipitation Data for Buttonwillow Station, Buttonwillow, California. Average low and high temperatures during the summer vary from the high 60s to the mid 90s, respectively (in degrees Fahrenheit [ºF]). Summer precipitation is extremely low due to the strong stationary high-pressure system located off the coast that prevents most weather systems from moving through the area. The Project Site receives an average of 6 inches of rain annually. During the winter, average low and high temperatures vary from the mid-30s to the mid-50s, respectively. About 80 percent of the precipitation in the area occurs from November through March, generally in association with storm systems that move through the region.

**Table 3-1**
**Temperature and Precipitation**
**Data for Buttonwillow Station Buttonwillow, California**

| Month | Average Temperatures (°F)[a] | | | Precipitation (inches) |
|---|---|---|---|---|
| | Low | High | Daily | |
| January | 35.1 | 56.3 | 45.7 | 1.08 |
| February | 38.9 | 63.2 | 51.1 | 1.08 |
| March | 43 | 69.1 | 56 | 1 |
| April | 47.2 | 76 | 61.6 | 0.56 |
| May | 54 | 84.7 | 69.4 | 0.22 |
| June | 60 | 92.4 | 76.2 | 0.05 |
| July | 65.2 | 98.4 | 81.8 | 0.02 |
| August | 63.2 | 96.7 | 80 | 0.02 |
| September | 57.6 | 91.5 | 74.6 | 0.13 |
| October | 48.6 | 81.5 | 65.1 | 0.28 |
| November | 39.1 | 67.4 | 53.3 | 0.54 |
| December | 34.4 | 57.1 | 45.8 | 0.67 |
| **Annual Average** | **48.9** | **77.9** | **63.4** | **5.65** |

Source: Western Regional Climate Center February 2009.
**Note:**

[a] Average temperature and precipitation data represent 1940–2008.

Large climatic variations occur within relatively short distances, given the nature of the surrounding topography. These zones may be classified as valley, mountain, and desert. The overall climate, however, is warm and semi-arid.

The annual and seasonal wind roses are presented in Figures A-1 through A-5 of the Modeling Protocol, which is included in Appendix C. Winds for all seasons and all years blow predominantly from the sector between northwest and north, although the directional pattern is more variable during the fall and winter seasons.

## 3.2 EXISTING AIR QUALITY

Ambient air quality standards have been set by both the federal government and the state of California to protect public health and welfare with an adequate margin of safety. Pollutants for which National Ambient Air Quality Standards (NAAQS) or California Ambient Air Quality Standards (CAAQS) have been set are often referred to as "criteria" air pollutants. The term is derived from the comprehensive health and damage effects review that culminates in pollutant-specific air quality criteria documents, which precede NAAQS and CAAQS standard setting. These standards are reviewed on a legally prescribed frequency and revised as new health and welfare effects data warrant.

Each NAAQS or CAAQS is based on a specific averaging time over which the concentration is measured. Different averaging times are based upon protection of short-term, high-dosage effects or longer-term, low dosage effects. NAAQS may be exceeded no more than once per year. CAAQS are not to be exceeded.

A protocol was submitted to air regulatory agencies with jurisdiction over this Project that included the list of locations of available CARB ambient air quality monitoring stations (URS 2009). The ambient air quality in Kern County is represented by data monitored at four permanent air monitoring stations. Air quality monitoring data to represent existing air quality in the Project area were obtained from the USEPA Air Data (2008) and the CARB-California Air Quality Data website (2008). The maximum concentration recorded at these monitoring stations over the most recent three-year period will be used as a conservative representation of existing air quality condition at the Project Site.

The monitoring station in the county that is closest to the Project Site is the Shafter-Walker Street Station, within 13 miles (21 kilometer [km]) from the Project Site. However, this station only measures ozone ($O_3$), $NO_x$, and total VOCs. The Bakersfield Golden Highway station is the next closest and the most complete station that measures all pollutants except $SO_2$. This station is located approximately 21 miles (33 km) to the east of the Project Site. The only station in the SJVAB that monitors $SO_2$ is the CARB station at First Street in Fresno, located approximately 102 miles (164 km) to the north. Sulfur dioxide data have only been recorded in Fresno County for 3 of the last 10 years (2003, 2007, 2008), a practice that is justified by the low levels that have been recorded for this pollutant when measurements have been made. Air quality measurements taken at these stations are presented in Tables 3-2 through 3-7. These tables show the pollutant levels recorded for the previous 10-year periods, as available. For the air quality impact analysis, the maximum background concentration from the past 3 years from all monitoring stations was used.

The monitoring data indicate that the air is in compliance with all federal NAAQS and CAAQS for $NO_2$, CO, and $SO_2$ for all averaging periods. However, the monitoring data indicate that the NAAQS and/or the CAAQS are periodically exceeded for $O_3$, $PM_{10}$, and $PM_{2.5}$.

**Ozone ($O_3$).** SJVAB is designated as a non-attainment area for $O_3$ (state 1-hour, state 8-hour, and federal 8-hour). Table 3-2, Ambient Ozone Levels at Shafter-Walker Street, 1999-2008, shows that the 8-hour $O_3$ NAAQS of 0.08 parts per million (ppm) has been frequently exceeded in the past 10 years at the Shafter-Walker Street Station and that the 1-hour $O_3$ NAAQS of 0.12 ppm (a standard revoked by USEPA on 15 June 2005) has not been exceeded in the last 10 years at the Shafter-Walker Street Station except for 2008. The more stringent 1-hour CAAQS of 0.09 ppm has been frequently exceeded in the past 10 years at the Shafter-Walker Street Station. The federal standard requires maintaining 0.08 ppm as a 3-year average of the fourth-highest daily maximum value. Therefore, the number of days that the maximum concentration exceeds the standard concentration is not the number of violations of the standard for the year.

**Table 3-2**
**Ambient Ozone Levels at Shafter-Walker Street 1999-2008**
**(ppm)**

| | **1999** | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** |
|---|---|---|---|---|---|---|---|---|---|---|
| **Shafter-Walker Street Station, Kern County** | | | | | | | | | | |
| Maximum 1-Hour Average | 0.116 | 0.123 | 0.110 | 0.112 | 0.121 | 0.100 | 0.104 | 0.106 | 0.111 | **0.131** |
| Number of Days Exceeding California 1-Hour Standard (0.09 ppm) | 31 | 18 | 26 | 22 | 18 | 3 | 14 | **20** | 3 | 14 |
| Number of Days Exceeding Federal 1-Hour Standard (0.12 ppm) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **1** |
| Maximum 8-Hour Average | 0.097 | 0.106 | 0.104 | 0.100 | 0.104 | 0.092 | 0.096 | 0.099 | 0.102 | **0.111** |
| Number of Days Exceeding Federal 8-Hour Standard (0.08 ppm)[a] | 25 | 25 | 30 | 25 | 15 | 3 | 15 | **55** | 18 | 33 |

Source: California Air Resources Board (CARB), 2009, www.arb.ca.gov; USEPA AIRS, 2009, www.epa.gov/air/data/index.html. Last Update: 9 March 2009

**Notes:**

a Number of days with an 8-hour average exceeding federal standard concentration of 0.08 ppm. Regulatory standard is to maintain 0.08 ppm as a 3-year average of the fourth-highest daily maximum. Therefore, number of days exceeding standard concentration is not the number of violations of the standard for the year.

1 Maximum average values occurring during the most recent 3 years are indicated in bold.

2 National standards, other than those for $O_3$ and based on annual averages, are not to be exceeded more than once a year. The $O_3$ standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one.

3 New federal 8-hour $O_3$ and fine particulate matter ($PM_{2.5}$) standards were promulgated by USEPA on 18 July 1997. The federal 1-hour $O_3$ standard was revoked by USEPA on 15 June 2005.

ppm = parts per million

**Particulate Matter ($PM_{10}$ and $PM_{2.5}$).** SJVAB is designated as a non-attainment area for $PM_{10}$ and $PM_{2.5}$. Table 3-3, Ambient $PM_{10}$ Levels at Bakersfield Golden State Highway, 1999-,-2008, shows that the 24-hour average CAAQS of 50 micrograms per cubic meter (µg/m$^3$) for $PM_{10}$ has been frequently exceeded in the Bakersfield area. The 24-hour average $PM_{10}$ NAAQS of 150 μg/m$^3$ was exceeded six times within the past 10 years (in 1999 to 2002, 2006, and 2008). The maximum 24-hour $PM_{10}$ background concentration of 266 μg/m$^3$ was measured at the Bakersfield Golden Highway Station in 2008. 2008.

The annual geometric mean presented in Table 3-3, Ambient $PM_{10}$ Levels at Bakersfield Golden State Highway, 1999 - 2008, is also called the state annual average and is a geometric mean of all measurements. The annual arithmetic mean is also called the national annual average and is an arithmetic average of the four arithmetic quarterly averages (the federal $PM_{10}$ standard was revoked on 22 September 2006). All of the annual geometric concentrations from 1999 to 2006 are above the California $PM_{10}$ ambient air quality standard of 20 μg/m$^3$. The annual geometric concentrations from 2007 and 2008 are currently unavailable.

The annual and 24-hour $PM_{2.5}$ data are presented in Table 3-4, Ambient $PM_{2.5}$ Levels at Bakersfield Golden State Highway, 1999-2008. $PM_{2.5}$ data have a relatively short collection history. The 3-year average, 98$^{th}$ percentile is above the NAAQS of 35 μg/m$^3$. The 3-year average, arithmetic mean is above the CAAQS of 12 μg/m$^3$.

**Table 3-3**
**Ambient $PM_{10}$ Levels at Bakersfield-Golden State Highway 1999 --2008**
**(μg/m$^3$)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Bakersfield-Golden State Highway Station, Kern County** | | | | | | | | | | |
| Maximum 24-Hour Average | 186.0 | 153.0 | 216.0 | 194.0 | 134.0 | 84.0 | 109.0 | 162.0 | 135.0 | **266.**8 |
| Annual Geometric Mean | 60.1 | 53.9 | -- | 59.9 | 52.4 | 43 | 43.4 | **56.5** | -- | -- |
| Annual Arithmetic Mean | 59.5 | 53.1 | 54.4 | 59.2 | 52.4 | 42.8 | 43.2 | **55.4** | 54.8 | 50.4 |
| Estimated Number of Days Exceeding California 24-Hour Standard (50 μg/m$^3$) | 28 | 26 | 29 | 42 | 26 | 19 | 20 | 27 | 28 | **29** |

Source: California Air Resources Board (CARB), 2009, www.arb.ca.gov.

Last Update: 1 April 2009

**Notes:**

Maximum average values occurring during the most recent 3 years are indicated in bold.

-- = Data not available

μg/m$^3$ = micrograms per cubic meter

**Table 3-4**
**Ambient $PM_{2.5}$ Levels at Bakersfield-Golden State Highway 1999-2008**
**($\mu g/m^3$)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Bakersfield-Golden State Highway Station, Kern County** | | | | | | | | | | |
| Maximum 24-Hour Average | 133.9 | 108.1 | 120.4 | 85.0 | 67.8 | 66.6 | 83.6 | 76.4 | **154.0** | 88.7 |
| Estimated Number of Days Exceeding Federal 24-Hour Standard (35 $\mu g/m^3$) | 68.5 | 66.8 | 44.6 | 84.9 | 45.4 | 44 | 45.7 | **38.7** | -- | -- |
| 1-Year 98th Percentile | 95.3 | 93.9 | 95.9 | 80.4 | 51.9 | 53.9 | 74.9 | 64.4 | **67.7** | 60.8 |
| 3-Year Average, 98th Percentile[a] | -- | -- | 95 | 90 | 76 | 62 | 60 | 64 | **69** | 64 |
| Annual Arithmetic Mean | 26.2 | 22.6 | 21.8 | 24.1 | 19.6 | 18.2 | 19.1 | 18.6 | **25.5** | -- |
| 3-Year Average, Arithmetic Mean[b] | -- | -- | 24 | 23 | 22 | 21 | 19 | 19 | **21** | -- |
| State Annual Average | 133.9 | 108.1 | 120.4 | 85.0 | 67.8 | 66.6 | 83.6 | 76.4 | **154.0** | 88.7 |

Source: California Air Resources Board (CARB), 2009, www.arb.ca.gov.

Last Update: 1 April 2009

**Notes:**

a The 3-Year Average, 98th Percentile is above the National Ambient Air Quality Standard of 35 $\mu g/m^3$.

b The 3-Year Average, Arithmetic Mean is above the California Ambient Air Quality Standard of 12 $\mu g/m^3$

Maximum average values occurring during the most recent 3 years are indicated in bold.

-- = Data not available

$\mu g/m^3$ = micrograms per cubic meter

**Carbon Monoxide (CO).** SJVAB is designated as an attainment area for CO. The data in Table 3-5, Ambient CO Levels at Bakersfield-Golden State Highway, 1999-1999-2008, show that the measured concentrations of CO are all below the applicable federal and California standards.

**Table 3-5**
**Ambient CO Levels at Bakersfield-Golden State Highway 1990-2008**
**(ppm)**

| | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Bakersfield-Golden State Highway Station, Kern County** | | | | | | | | | | |
| Maximum 1-Hour Average[a] | 5.4 | 10.1 | 8.1 | 4.5 | 4.5 | 4.1 | 3.2 | 3.3 | 2.8 | **3.5** |
| Maximum 8-Hour Average[b] | 4.06 | 5.38 | 3.49 | 2.5 | 3.7 | 2.6 | 2.1 | **2.19** | 1.97 | 2.17 |

Source: California Air Resources Board (CARB), 2009, www.arb.ca.gov. ; USEPA AIRS, 2009, www.epa.gov/air/data/index.html

Last Update: 1 April 2009

**Notes:**

Maximum average values occurring during the most recent 3 years are indicated in bold.

a All 1-hour concentrations are below the federal and California CO ambient air quality standards of 35 ppm and 20 ppm, respectively.

b All 8-hour concentrations are below the federal and California CO ambient air quality standard of 9 ppm.

ppm = parts per million

**<u>Nitrogen Oxides</u>** ($NO_x$)**.** SJVAB is designated as an attainment area for $NO_2$. The data in Table 3-6, Ambient $NO_2$ Levels at Shafter-Walker Street and Bakersfield-Golden State Highway Station 1999 -2008, show that the measured concentrations of $NO_2$, are all below the applicable federal and California standards.

**Table 3-6**
**Ambient $NO_2$ Levels at Shafter-Walker Street 1999 -2008**
**(ppm)**

| | **1999** | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** |
|---|---|---|---|---|---|---|---|---|---|---|
| **Shafter-Walker Street Station, Kern County** | | | | | | | | | | |
| Maximum 1-Hour Average[a] | 0.073 | 0.064 | 0.072 | 0.062 | 0.071 | 0.074 | 0.063 | 0.100 | **0.101** | 0.045 |
| **Bakersfield-Golden State Highway Station, Kern County** | | | | | | | | | | |
| Annual Average[b] | 0.027 | 0.023 | 0.015 | 0.024 | 0.023 | 0.021 | 0.021 | **0.021** | 0.020 | 0.017 |

Source: California Air Resources Board (CARB), 2009, www.arb.ca.gov. ; USEPA AIRS, 2009, www.epa.gov/air/data/index.html
Last Update: 1 April 2009
**Notes:**
Maximum average values occurring during the most recent 3 years are indicated in bold.
Arithmetic average 1-hour for the 2006 – 2008 period equals 0.082 ppm.
a All 1-hour concentrations are below the California $NO_2$ ambient air quality standard of 0.25 ppm.
b All annual average concentrations are below the federal $NO_2$ ambient air quality standard of 0.053 ppm.
ppm = parts per million.

**<u>Sulfur Dioxide</u>** ($SO_2$)**.** SJVAB is designated as an attainment area for SO2. The data in Table 3-7, Ambient SO2 Levels Nearest to the Project Location, 1999-2008, show that the measured concentrations of SO2 are all below the applicable federal and California standards.

**Table 3-7**
**Ambient $SO_2$ Levels Nearest to the Project Location 1999-2008**
**(ppm)**

| | **1999** | **2000** | **2001** | **2003** | **2007** | **2008** |
|---|---|---|---|---|---|---|
| **Monitoring Station** | **Bakersfield-5558 California Avenue** | **Bakersfield-5558 California Avenue** | **Bakersfield-5558 California Avenue** | **Fresno-Fremont School** | **Fresno-First St** | **Fresno-First St** |
| Maximum 1-Hour Average[a] | -- | -- | 0.030 | 0.009 | 0.130[d] | 0.060 |
| Maximum 24-Hour Average[b] | 0.006 | 0.003 | 0.005 | 0.004 | 0.052 | 0.027 |
| Annual Average[c] | 0.003 | 0.003 | 0.002 | 0.002 | 0.007 | 0.010 |

Source: California Air Resources Board (CARB), 2009, www.arb.ca.gov. ; USEPA AIRS, 2009, www.epa.gov/air/data/index.html.
Last Update: 1 April 20099
**Notes:**
a All 1-hour average concentrations are below the California $SO_2$ ambient air quality standard of 0.25 ppm (655 $\mu g/m^3$).
b All 24-hour average concentrations are below the California $SO_2$ ambient air quality standard of 0.04 ppm (105 $\mu g/m^3$) and the National Ambient Air Quality Standard (NAAQS) of 0.14 ppm (365 $\mu g/m^3$).
c All annual average concentrations are below the $SO_2$ NAAQS of 0.03 ppm (80 $\mu g/m^3$)
d It was observed that higher monitoring concentrations were observed at the Fresno -1st Street station on July 4 and July 5, 2007 (the day of and the day after Independence Day). Because these values are much higher than concentrations observed during the rest of the year, they were assumed to have been caused by fireworks. These values will fall into the category EPA Rule 40 CFR 50.14. Therefore, concentrations on July 4 and Jul 5, 2007 were not considered, and the next highest 1-hour and 3-hour concentrations were used instead. Confirmed in an email from Leland Villalvazo on February 4, 2009.
-- = Data not available

ppm = parts per million

BACT was discussed in Section 2.0 Laws, Ordinances, Regulations, and Standards and presented in Table 2-1. The full BACT analysis is presented in Appendix A.

The Project is a nominal 250 MW IGCC power generating facility consisting of a gasification block/syngas production with carbon capture capability and a combined-cycle power block. The gasification block will feature GE Quench gasifiers and sour shift, and a Rectisol acid gas removal (AGR) unit to remove sulfur components and recover carbon dioxide. The power block will feature one GE 7FB combustion turbine-generator (CTG) that can be fueled with hydrogen-rich syngas from the gasification plant, natural gas, or a mixture of the two; a heat recovery steam generator (HRSG) with duct firing of hydrogen-rich syngas or natural gas; a condensing steam turbine-generator; and a GE LMS100®simple cycle CTG fueled with natural gas as an auxiliary combustion turbine. The operational emissions from the Project are mainly generated from the combustion of the hydrogen-rich syngas. Other emission sources include cooling towers, solids handling, and an auxiliary boiler and auxiliary CTG. For emission calculation purposes, each emission source is categorized as power block, gasification block, or ancillary equipment. The classification of the criteria pollutant emission sources from the Project is as follows.

**Power Block**

- Combustion Turbine (GE 7FB)
- Auxiliary CTG (GE LMS100®)
- Power Block Cooling Tower

**Gasification Block**

- Gasifier Refractory Heaters
- Auxiliary Boiler
- Gasification Flare
- SRU Flare
- Rectisol Flare
- Tail Gas Thermal Oxidizer
- ASU and Gasification Cooling Towers
- Carbon Dioxide Vent
- Dust collection (Feedstock)

**Ancillary Equipment**

- Diesel Generator
- Emergency Diesel Firewater Pump

## 5.1 POWER BLOCK

### *Power Block CTG/HRSG Operating Emissions*

The most significant emission source of the Project will be the CTG/HRSG train. The power block design will be optimized for performance on 100 percent hydrogen-rich syngas, 100 percent natural gas, or co-firing hydrogen-rich syngas and natural gas. Most of the hydrogen-rich syngas from the gasification plant will be used to fully load the CTG, with any excess (up to about 10 to 14%) duct fired in the HRSG. The CTG will operate on hydrogen-rich syngas, natural gas, or a mixture of the two (45 to 90% hydrogen-rich syngas) over the compliance load range of 60 to 100 percent. The CTG will be co-fired with natural gas as required to maintain baseload operation whenever the quantity of hydrogen-rich syngas is insufficient.

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 and without 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 below in Table 5-1, Maximum CTG/HRSG Operating Schedule.

Operational emissions from the CTG/HRSG were estimated for all the applicable scenarios using base emission rates and startup/shutdown emissions. The base criteria pollutant emission rates provided by the turbine vendor and the engineer for three load conditions (60%, 80%, and 100%) and three ambient temperatures (20ºF, 65ºF, and 97ºF) when firing natural gas, syngas, or co-firing are presented in Table 5-2, 1-Hour Operating Emission Rates for CTG/HRSG Operating Load Scenarios.

**Table 5-1**
**Maximum CTG/HRSG Operating Schedule**

| Operating Conditions | Annual Numbers |
|---|---|
| Total Hours of Operation | 8,322 |
| Total Number of Cold Starts | 10 |
| Cold Start Duration (hr) | 3 |
| Total Number of Hot Starts | 10 |
| Hot Start Duration (hr) | 1 |
| Total Number of Shutdowns | 20 |
| Shutdown Duration (hr) | 0.5 |
| Duct Burner Operation (hr) | 8,272 |

Source: HECA Project

**Notes:**

CTG = combustion turbine generator

HRSG = heat recovery steam generator

**Table 5-2**
**1-Hour Operating Emission Rates for CTG/HRSG Operating Load Scenarios**

| Ambient Temperature | UNITS | Winter Minimum, 20°F | | | | Yearly Average, 65°F | | | | Summer Maximum, 97°F | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CTG Load Level | % 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 Natural Gas** | | | | | | | | | | | | | |
| $NO_x$ (@ 4.0 ppm) | lb/hr | 36.3 | 29.0 | 24.8 | 20.8 | 35.1 | 27.0 | 23.1 | 19.4 | 33.3 | 26.1 | 22.4 | 18.7 |
| CO (@ 5.0 ppm) | lb/hr | 27.6 | 22.1 | 18.8 | 15.8 | 26.7 | 20.5 | 17.6 | 14.8 | 25.3 | 19.8 | 17.0 | 14.2 |
| VOC (@ 2.0 ppm) | lb/hr | 6.3 | 5.0 | 4.3 | 3.6 | 6.1 | 4.7 | 4.0 | 3.4 | 5.8 | 4.5 | 3.9 | 3.2 |
| $SO_2$ (@ 12.65 ppmv in fuel) | lb/hr | 5.1 | 4.1 | 3.5 | 3.0 | 4.8 | 3.8 | 3.3 | 2.8 | 4.7 | 3.7 | 3.2 | 2.7 |
| $PM_{10} = PM_{2.5}$ | lb/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) | lb/hr | 16.7 | 13.4 | 11.4 | 9.6 | 16.2 | 12.5 | 10.7 | 9.0 | 15.4 | 12.1 | 10.3 | 8.6 |
| **Average Emission Rates from CTG(lbs/hr/turbine) - Normal Operation Syngas** | | | | | | | | | | | | | |
| $NO_x$ (@ 4.0 ppm) | lb/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) | lb/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) | lb/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 in fuel) | lb/hr | | 6.1 | 5.2 | 4.4 | 6.8 | 6.1 | 5.1 | 4.3 | 6.8 | 6.0 | 5.1 | 4.3 |
| $PM_{10} = PM_{2.5}$ | lb/hr | | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 |
| $NH_3$ (@ 5.0 ppm slip) | lb/hr | | 17.2 | 14.6 | 12.0 | 18.4 | 17.0 | 14.3 | 11.8 | 18.4 | 17.6 | 14.3 | 11.8 |
| **Average Emission Rates from CTG (lbs/hr/turbine) - Normal Operation Co-firing** | | | | | | | | | | | | | |
| $NO_x$ (@ 4.0 ppm) | lb/hr | 41.3 | 34.0 | | | 38.7 | 31.7 | | | | | | |
| CO (@ 5.0 ppm) | lb/hr | 31.4 | 25.9 | | | 29.4 | 24.1 | | | | | | |
| VOC (@ 2.0 ppm) | lb/hr | 7.2 | 5.9 | | | 6.7 | 5.5 | | | | | | |
| $SO_2$ (@ 6.7 ppmv in fuel) | lb/hr | 7.4 | 5.2 | | | 7.0 | 4.8 | | | | | | |
| $PM_{10} = PM_{2.5}$ | lb/hr | 24.0 | 24.0 | | | 24.0 | 24.0 | | | | | | |
| $NH_3$ (@ 5.0 ppm slip) | lb/hr | 19.1 | 15.7 | | | 17.9 | 14.6 | | | | | | |

Source: HECA Project

**Notes:**

- Co-firing emissions are controlled at the same amount as natural gas.
- Emission rates not provided were not necessary to determine the maximum hourly, 3-hour, 8-hour, 24-hour emission rates or the annual average emission rates.

CO = carbon monoxide
CTG = combustion turbine generator
HRSG = heat recovery steam generator
$NH_3$ = ammonia
ppm = parts per million
$PM_{10}$ = particulate matter 10 microns in diameter and is assumed to equal $PM_{2.5}$ = particulate matter 10 microns in diameter
$SO_2$ = sulfur dioxide

**Table 5-2**
**1-Hour Operating Emission Rates for CTG/HRSG Operating Load Scenarios**

| Ambient Temperature | UNITS | Winter Minimum, 20°F | Yearly Average, 65°F | Summer Maximum, 97°F |
|---|---|---|---|---|

$NO_X$ = nitrogen oxides
VOC = volatile organic compound

### CTG/HRSG Startup and Shutdown Emissions

Because startup and shutdown events typically had higher emission rates than operating conditions, they were incorporated into the short- and long-term emissions estimates for the CTG/HRSG for modeling purposes. When firing natural gas, syngas, or co-firing, the CTG/HRSG will always be started burning natural gas fuel. Therefore, the expected emissions and duration of startup events summarized in Table 5-3, CTG/HRSG Criteria Pollutant Emission Rates During Startup and Shutdown, reflect the emissions from natural gas startup and shutdown. Based on vendor information, a cold startup of the CTG and associated steam turbine is expected to take 180 minutes.

Similarly, the hot start for the CTG/HRSG will occur over intervals of 60 minutes, and shutdown will be completed in 30 minutes. During a shutdown event, the efficiency of the emission controls will continue to function at normal operating levels down to a load of 60 percent; thus, shutdown periods and emissions are measured from the time this load is reached.

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

### CTG/HRSG Emissions Scenarios for Modeling

Reasonable worst-case short-term emissions from the turbines were calculated for use in the air quality modeling. For worst-case 1-hour emissions, the worst-case startup $NO_x$ and CO emission rate was used. Based on the startup information, $NO_x$ and CO emissions during a hot startup and a cold startup, respectively, are the worst-case conditions. Sulfur oxide ($SO_X$) emissions are maximized at peak fuel usage for all firing scenarios (natural gas, syngas, and co-firing).

The 3-hour $SO_X$ emission rate for all firing scenarios (natural gas, syngas, and co-firing) was based on the scenario at peak fuel usage for corresponding firing scenarios.

The 8-hour CO emission rate for all firing scenarios (natural gas, syngas, and co-firing) was calculated assuming two full cold start, three shutdown and the balance (0.5 hour) operating at the worst-case operating condition (at peak fuel usage for corresponding firing scenarios).

The 24-hour $NO_x$ (for visibility) rate was calculated assuming 20 hours of natural gas firing at the winter minimum (20$^o$F) without duct firing and 4 hours of co-firing at the winter minimum (20$^o$F) without duct firing. $PM_{10}$ and $SO_2$ worst-case 24-hour emission rates were calculated assuming the worst-case operating condition (at peak fuel usage for corresponding firing scenario)

Table 5-4, 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 6, Modeling Impact Analysis. Note that modeling of turbine commissioning impacts was conducted separately due to the temporary, one-time nature of this activity.

**Table 5-3**
**CTG/HRSG Criteria Pollutant Emission Rates During Startup and Shutdown**

| Cold Startup | | | Hot Startup | | | Shutdown | | |
|---|---|---|---|---|---|---|---|---|
| **180 (min. in cold startup)** | **Max 1-hr. (lb/hr)** | **Total (lb/180 min.)** | **60 (min. in hot startup)** | **Max 1-hr. (lb/hr)** | **Total lb/60 min.)** | **30 (min. in shutdown)** | **Max 1-hr. (lb/hr)** | **Total (lb/30 min.)** |
| $NO_X$ | 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 |
| $SO_2$ | 5.1 | 15.3 | $SO_2$ | 5.1 | 5.1 | $SO_2$ | 2.6 | 2.6 |
| $PM_{10} = PM_{2.5}$ | 21.3 | 64.0 | $PM_{10} = PM_{2.5}$ | 23.0 | 23.0 | $PM_{10} = PM_{2.5}$ | 5.0 | 5.0 |

Source: HECA Project

**Notes:**

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 $SO_2$ emissions. Startup and shutdown emissions are assumed equal to normal operations (burning natural gas) at the max emission rate.

Startup/shutdown duration defined as operation of CTG below 60 % load when gaseous emission rates (lb/hr basis) exceed the controlled rates defined as normal operation

CO = carbon monoxide

$NO_X$ = nitrogen oxides

$PM_{10}$ = particulate matter 10 microns in diameter and is assumed to equal $PM_{2.5}$ = particulate matter 10 microns in diameter

$SO_2$ = sulfur dioxide

VOC = volatile organic compounds

**Table 5-4**
**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 (Natural Gas) | CTG/HRSG (Syngas) | CTG/HRSG (Co-firing) |
|---|---|---|---|---|---|
| 1 hour | **$NO_X$:** Cold startup hour | $NO_X$ | 167.0 | 167.0 | 167.0 |
| | **CO:** Cold startup hour | CO | 1,679.7 | 1,679.7 | 1,679.7 |
| | **$SO_X$:** Full-load turbine operation with duct firing at peak fuel usage | $SO_X$ | 5.1 | 6.8 | 7.4 |
| 3 hour | **$SO_X$:** Continuous full-load turbine operation with duct firing (both turbines) at peak fuel usage | $SO_X$ | 15.3 | 20.5 | 22.1 |
| 8 hour | **CO:** Two cold start, three shutdown, and remainder of period at full load operation with full duct firing (both turbines) at peak fuel usage | CO | 10,469.8 | 10,465.1 | 10,471.7 |
| 24 hour | **$NO_X$:** 20 hours of natural gas firing at the winter minimum (20°F) without duct firing and 4 hours of co-firing at the winter minimum (20°F) without duct firing | $NO_X$ | 20 hrs = 580.5<br>Total = 716.5 | n/a | 4 hrs = 136.0<br>Total = 716.5 |
| | **$SO_X$, $PM_{10}$:** Continuous full-load turbine operation with duct firing (both turbines) at peak fuel usage; except $PM_{10}$ for natural gas: four cold start, four shutdown, and remainder of period at full load operation with full duct firing (both turbines) at peak fuel usage | $PM_{10}$ = $PM_{2.5}$ | 432 | 576 | 576 |
| | | $SO_X$ | 122.4 | 163.8 | 177.2 |
| Annual | **$NO_X$, CO, VOC, $PM_{10}$, and $SO_X$:** 10 hot starts, 10 cold starts and 20 shutdowns, and remainder of turbine operates at full load with duct firing | $NO_X$ | 296,044.0 | 334,353.0 | 325,712.3 |
| | | CO | 277,817.2 | 206,919.2 | 300,390.9 |
| | | VOC | 59,906.8 | 37,984.6 | 65,066.5 |
| | | $PM_{10}$ = $PM_{2.5}$ | 149,866.0 | 199,498.0 | 199,498.0 |
| | | $SO_X$ | 40,045.4 | 56,713.0 | 58,357.9 |

Source: HECA Project

**Notes:**

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

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 and without duct firing. For purposes of developing the annual emission estimates, the contributions associated with all normal operating hours were calculated based on assumed 100 percent turbine load and ambient temperature of 65ºF for the specified number of hours per year. Emissions for normal operating hours with duct firing assumed the maximum duct burner fuel input rate at 65°F. The analysis is conservative because no credit was taken for downtime that would normally follow each shutdown. Estimated maximum annual emissions for the GE 7FB turbine are presented in Table 5-5, Average Annual Emissions per Turbine Operating Scenario. Emissions calculations for all scenarios are contained in Appendix B.

**Table 5-5**
**Average Annual Emissions per Turbine Operating Scenario**

| Pollutant | HRSG Stack - Nat Gas (tons/yr/CT) | HRSG Stack - Syn Gas (tons/yr/CT) | HRSG Stack - Co Firing (tons/yr/CT) | Maximum (tons/yr/CT) |
|---|---|---|---|---|
| $NO_X$ | 148.0 | 167.2 | 162.9 | 167.2 |
| CO | 138.9 | 103.5 | 150.2 | 150.2 |
| VOC | 30.0 | 19.0 | 32.5 | 32.5 |
| $SO_2$ | 20.0 | 28.4 | 29.2 | 29.2 |
| $PM_{10}$ = $PM_{2.5}$ | 74.9 | 99.7 | 99.7 | 99.7 |
| $NH_3$ | 67.1 | 75.9 | 73.9 | 75.9 |

Source: HECA Project

**Notes:**

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

### *Natural Gas-fired Auxiliary CTG*

In addition to the main GE 7FB combined cycle turbine, the power block also includes a single natural gas fired auxiliary gas turbine to provide backup power to the gasification plant during forced outage periods and to provide beneficial spot market power production to the grid. The auxiliary CTG will be equipped with water injection and SCR for the control of $NO_x$ emissions and an oxidation catalyst for control of emissions of CO and VOC. The auxiliary CTG is a natural gas fired GE LMS100® in a simple cycle configuration.

The auxiliary simple cycle CTG is designed to operate independently from the rest of the facility and can be used to supply additional export power when needed. The auxiliary CTG requires high pressure natural gas and the natural gas compressor will be operated whenever the auxiliary CTG is operated. Estimated annual emissions of air pollutants for the auxiliary CTG have been calculated based on the expected operating schedule presented below in Table 5-6, Maximum Auxiliary CTG Operating Schedule.

Operational emissions from the auxiliary CTG were estimated for all applicable scenarios using base emission rates and startup/shutdown emissions. The base criteria pollutant emission rates provided by the turbine vendor and the engineer for three load conditions (50%, 75%, and 100%) and three ambient temperatures (20ºF, 65ºF, and 97ºF) when firing natural gas are presented in Table 5-2, 1-Hour Operating Emission Rates for CTG/HRSG Operating Load Scenarios. Table 5-7, Auxiliary CTG Criteria Pollutant Emission Rates During Startup and Shutdown, summarizes the expected emissions and duration of startup and shutdown from the auxiliary CTG.

**Table 5-6**
**Maximum Auxiliary CTG Operating Schedule**

| | |
|---|---|
| Total Hours of Operation | 4,110 |
| Total Number of Cold Starts | 325 |
| Cold Start Duration (hr) | 0.2 |
| Total Number of Shutdowns | 325 |
| Shutdown Duration (hr) | 0.2 |
| Evaporative Cooling Operation (hr) | 4,000 |

Source: HECA Project

Assumptions: Average annual operational emissions are calculated using yearly average: 65°F, at 100% load, with evaporative cooling.

**Note:**

CTG = combustion turbine generator

**Table 5-7**
**Auxiliary CTG Criteria Pollutant Emission Rates During Startup and Shutdown**

| Cold Startup | | | Shutdown | | |
|---|---|---|---|---|---|
| **10 (min. in cold startup)** | **Max 1-hr. (lb/hr)** | **Total (lb/10 min.)** | **10.3 (min. in shutdown)** | **Max 1-hr. (lb/hr)** | **Total (lb/10.3 min.)** |
| $NO_X$ | 9.0 | 3.0 | NOx | 12.0 | 4.0 |
| CO | 30.6 | 10.2 | CO | 39.6 | 13.2 |
| VOC | 0.5 | 0.2 | VOC | 0.6 | 0.2 |
| $SO_2$ (@ 12.65 ppmv) | 1.9 | 0.3 | $SO_2$ | 1.9 | 0.3 |
| $PM_{10} = PM_{2.5}$ | 6.0 | 1.7 | $PM_{10} = PM_{2.5}$ | 6.0 | 1.7 |

Source: HECA Project
**Notes:**
$NO_x$, CO, and VOC startup and shutdown emissions (max 1-hr) assume 3 startup and 3 shut down.
Startup and shutdown $SO_2$ and $PM_{10}$ emissions will always be lower than normal operational emissions. Startup and shutdown emissions are assumed equal to normal operations max emission rate, with evaporative cooling.

CTG = combustion turbine generator
CO = carbon monoxide
$NO_X$ = nitrogen oxides
$PM_{10}$: = Particulate matter 10 microns in diameter
$PM_{2.5}$ = particulate matter 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal $PM_{10}$)
$SO_2$ = sulfur dioxide
VOC = volatile organic compounds

**Auxiliary CTG Emissions Scenarios for Modeling**

Reasonable worst-case short-term emissions from the auxiliary CTG were calculated for use in the air quality modeling. For worst-case 1-hour emissions, the worst-case startup scenario for $NO_x$ and CO was used. Based on the startup information, $NO_x$ and CO emissions were conservatively estimated as the contribution from three startups and three shutdowns over a 1-hour period. $SO_X$ emissions are maximized at normal operating scenario.

The 3-hour $SO_X$ emission rate is maximized at normal operating scenario.

The 8-hour CO emission rate was calculated assuming four cold starts and four shutdowns.

The 24-hour $NO_X$, emission rate was calculated assuming four cold starts, four shutdowns and the balance (10 hours) normal operation at maximum emission rate. $PM_{10}$ and $SO_X$ worst-case 24-hour emission rates were calculated assuming normal operation at the maximum emission rate

Table 5-8, Criteria Pollutant Sources and Emission Totals for the Worst-Case Auxiliary CTG Emissions Scenario for All Averaging Time, 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 6, Modeling Impact Analysis.

**Table 5-8**
**Criteria Pollutant Sources and Emission Totals for the Worst-Case Auxiliary CTG Emissions Scenario for All Averaging Times**

| Averaging Time | Worst-case Emission Scenarios by Operating Equipment | Pollutant | Emissions in pounds – Entire Period |
|---|---|---|---|
| 1 hour | **$NO_X$:** Contribution from three startups and three shutdowns over a 1-hour period. | $NO_X$ | 20.7 |
| | **CO:** Contribution from three startups and three shutdowns over a 1-hour period. | CO | 69.0 |
| | **$SO_X$:** Normal Operation at maximum emission rate. | $SO_X$ | 1.9 |
| 3 hour | **$SO_X$:** Normal Operation at maximum emission rate. | $SO_X$ | 5.6 |
| 8 hour | **CO:** Four cold startups and four shutdowns. | CO | 172.6 |
| 24 hour | **$NO_X$:** four cold starts, four shutdowns, and remainder of normal operation at maximum emission rate. | $NO_X$ | 212.4 |
| | **$SO_X$, $PM_{10}$:** Normal Operation at maximum emission rate. | $PM_{10}$ = $PM_{2.5}$ | 144.0 |
| | | $SO_X$ | 44.6 |
| Annual | **$NO_X$, CO, VOC, $PM_{10}$, and $SO_X$ :** 325 cold starts and 325 shutdowns, and remainder of turbine operates with evaporative cooling. | $NO_X$ | 34,840.6 |
| | | CO | 55,179.1 |
| | | VOC | 9,182.0 |
| | | $PM_{10}$ = $PM_{2.5}$ | 24,660.0 |
| | | $SO_X$ | 7,644.4 |

Source: HECA Project

**Notes:**

CO = carbon monoxide
CTG = combustion turbine generator
$NO_X$ = nitrogen oxides
$SO_X$ = sulfur oxides
$PM_{10}$ = particulate matter 10 microns in diameter
$PM_{2.5}$ = particulate matter 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal $PM_{10}$)
VOC = volatile organic compounds

**Power Block Cooling Tower**
Power cycle heat rejection will consist of a steam turbine generator surface condenser, cooling tower, and cooling water system. The heat rejection system receives exhaust steam from the low pressure steam turbine and condenses it to water for reuse. Approximately 175,000 gallons per minute (gpm) of water will be circulated in the power block cooling tower with an hourly circulation rate of 88 million pounds per hour.

The cooling water will circulate through a mechanical draft-cooling tower, which uses electric motor-driven fans to move the air into contact with the flow of the cooling water. The heat removed in the condenser will be discharged to the atmosphere by heating the air and through evaporation of some of the cooling water. Maximum drift, that is, the fine mist of water droplets entrained in the warm air leaving the cooling tower, will be limited to 0.0005 percent of the circulating water flow. Circulating water could range from 3,000 to 9,000 ppm total dissolved solids depending on makeup water quality and tower operation. Therefore, $PM_{10}$ emissions would vary proportionately. For emission calculation purposes, it is assumed that 9,000 ppm total dissolved solids is dissolved in the circulating cooling water. A summary of the power block cooling tower emissions is presented in Table 5-9, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix B.

## 5.2 GASIFICATION BLOCK

**Gasifier:** The gasification plant consists of three gasifiers. The plant will be capable of continuous operation of one or two gasifiers, each at up to maximum flow (each at 100 percent of rated operation). Each of the three gasification trains will have one natural gas fired burner used to warm the gasification refractory to facilitate startup. These burners will not operate when the gasification train is operating.

The only criteria pollutant emissions from the gasifier units are the by-products of the natural gas fired burners (3 total, 1 per gasifier) during start-up. The gasifier warming burners operate at 18 million British thermal units (MMBtu)/hour firing natural gas for a total of 1,800 hours of normal operation per year. A summary of the gasifier warming emissions is presented in Table 5-9, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix B.

During gasifier startup, unprocessed/unreacted vent gas is vented to the flaring system.

**Auxiliary Boiler:** The auxiliary boiler will provide steam to facilitate CTG startup and for other industrial purposes. The auxiliary boiler will be designed to burn pipeline-quality natural gas at the design maximum fuel flow rate of 142 MMBtu/hour (higher heating value). The auxiliary boiler emissions are based on 2,190 hours of operation per year. Emissions are based on vendor supplied emission factors. $NO_x$ emissions are based on 9 parts per million volumetric dry (ppmvd) at 3 percent $O_2$ with installation of ultra-low $NO_x$ combustors and flue gas recirculation. Carbon monoxide emissions are based on 50 ppmvd 3 percent $O_2$. A summary of auxiliary boiler emissions is presented in Table 5-10, Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas at 59°F. Emissions and calculations are included in Appendix B.

**Gasification Flare, SRU Flare, and Rectisol Flare System:** The gasification block will operate a Gasification flare to safely dispose of gasifier startup gases (see previous discussion) and syngas, generated during short-term combustion turbine outages and other unplanned power plant upsets or equipment failures. In addition, there will be an SRU flare installed to safely dispose of gas emissions from the AGR source during startup (after passing via a scrubber) or to oxidize releases during emergency or upset events. The Rectisol flare will be used to safely dispose of low temperature gas streams during startup, shutdown and unplanned upsets or emergency events.

During normal operation, the three flares will have pilot lights that will operate continuously. Emissions from the flares are generated from the continual operation of the natural gas fired pilot lights and from periodic vent gas that are oxidized during unsteady state operation of the gasification and power blocks. A summary of each flare emissions is presented in Table 5-9, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix B.

**Tail Gas Thermal Oxidizer:** Associated with the operation of the sulfur recovery process, the Project will incorporate a thermal oxidizer on the tail gas treating unit (TGTU). The thermal oxidizer will serve as a control device to oxidize any remaining $H_2S$ (after scrubbing) and other vent gas that are generated during startup, shutdown, and times of non-delivery of carbon dioxide product. In addition, miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) are directed to the thermal oxidizer during normal operation to prevent nuisance odors. The thermal oxidizer operates at high temperate and provides sufficient residence time in order to ensure essentially complete destruction of reduced sulfur compounds like $H_2S$ to $SO_2$. The thermal oxidizer fires natural gas continually to reach and maintain the required operating temperature for proper thermal destruction. Pollutant emissions are generated from the firing of natural gas and the periodic oxidation of vent gas during system upset. A summary of the tail gas oxidizer emissions is presented in Table 5-9, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix B.

**ASU and Gasification Cooling Towers:** The ASU and gasification block cooling water system designs are similar to the power block cooling design, but they have substantially lower duties. The ASU cooling tower is located in the ASU unit near the cooling loads. The ASU cooling tower has separate pumps and piping systems and is operated independently of the other cooling water systems. The ASU cooling tower circulation rate is approximately 40,200 gpm and the tower is supplied with high efficiency drift eliminators designed to reduce drift to less than 0.0005 percent of circulation.

The gasification unit cooling tower is collocated with the power block cooling tower. Each tower has a separate cooling water basin, pumps, and piping system, and operates independently. The gasification cooling tower circulation rate is about 42,300 gpm and the tower is supplied with high efficiency drift eliminators designed to reduce drift to less than 0.0005 percent of circulation. A summary of the ASU and gasification block cooling tower emissions is presented in Table 5-9, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix B.

**Carbon Dioxide Vent:** A carbon dioxide vent stack will allow for start-up and intermittent emergency venting of produced carbon dioxide when the carbon dioxide injection system is unavailable. The carbon dioxide vent will enable the Project to operate, rather than be disabled, by brief periods when the carbon dioxide injection system is unavailable, and in doing so, prevents gasifier shutdown and subsequent gasifier restart with associated emissions. The Project design indicates that the carbon dioxide vent stack will be located beyond the downwash zones caused by the structures associated with the Project. However, the physical height of the carbon dioxide vent stack of 79.3 meters (260 feet) is greater than the *de-minimus* Good Engineering Practice height of 65 meters.

A 260-foot stack height was chosen to satisfy HEI's inherently safe design practices to minimize ground-level carbon dioxide concentrations in the event of a carbon dioxide vent under very low wind speeds.

The carbon dioxide vent exhaust stream will be nearly all carbon dioxide, with small amounts of CO and $H_2S$. A summary of the carbon dioxide vent stack emissions is presented in Table 5-9, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix B.

**Dust collection (Feedstock):** In addition to the sources above, there will be emissions of $PM_{10}$ from feedstock and gasifier solids materials handling operations. These operations include bulk material unloading, loading, belt conveying, belt transfer points, silo loading, and reclaim. A summary of the dust collection system emissions is presented in Table 5-9, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix B

### *Ancillary Equipment*

**Emergency Generator Engine and Firewater Pump Engine:** The Project will include two 2,800 horsepower standby diesel generators and one 556 horsepower, standby firewater pump, located adjacent to the firewater tank. The diesel engines will exclusively combust ultra low sulfur (15 ppm) No. 2 diesel fuel.

The 2,800 horsepower diesel engines are installed in an outdoor enclosure and will be connected to the 480 volt (V) switchgear. The switchgear supplies essential service power to critical lube oil and cooling pumps, gasification and auxiliary steam systems, gasification quench system, station battery chargers, uninterruptible power supply, heat tracing, control room and emergency exit lighting, and other critical plant loads. Emissions were estimated based on hourly manufacturers' emission rates as well as USEPA Tier 4 emissions standards for 2011 model equipment. Sulfur dioxide emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur. Emissions estimates for the three diesel engines are shown in Table 5-9, Total Combined Annual Criteria Pollutant Emissions. The annual emissions from these engines are based on a maximum non-emergency use rate of 50 hours of operation per year each for the emergency generator engines and 100 hours of operation per year for the fire pump engine.

## 5.3 TOTAL COMBINED FACILITY-WIDE EMISSIONS

The total combined annual emissions from all emission sources of the Project are shown in Table 5-9, Total Combined Annual Criteria Pollutant Emissions.

## Table 5-9
## Total Combined Annual Criteria Pollutant Emissions

| Pollutant | Total Annual (ton/yr) | HRSG Stack Maximum[1] (ton/yr) | Auxiliary CTG (ton/yr) | Cooling Towers[2] (ton/yr) | Auxiliary Boiler (ton/yr) | Emergency Generators[3] (ton/yr) | Fire Water Pump (ton/yr) | Gasification Flare (ton/yr) | SRUSRU Flare (ton/yr) | Rectisol Flare (ton/yr) | Tail Gas Thermal Oxidizer (ton/yr) | $CO_2$ Vent (ton/yr) | Gasifier (ton/yr) | Feedstock[4] (ton/yr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $NO_X$ | 203.8 | 167.2 | 17.4 | -- | 1.7 | 0.2 | 0.1 | 4.3 | 0.2 | 0.2 | 10.9 | -- | 1.8 | -- |
| CO | 350.3 | 150.2 | 27.6 | -- | 5.8 | 0.1 | 0.2 | 48.8 | 0.1 | 0.1 | 9.1 | 106.9 | 1.5 | -- |
| VOC | 40.7 | 32.5 | 4.6 | -- | 0.6 | 0.03 | 0.01 | 0.003 | 0.002 | 0.002 | 0.3 | 2.4 | 0.1 | -- |
| $SO_2$ | 42.2 | 29.2 | 3.8 | -- | 0.3 | 0.001 | 0.0003 | 0.004 | 0.055 | 0.003 | 8.8 | -- | 0.03 | -- |
| $PM_{10}$ | 141.1 | 99.7 | 12.3 | 24.1 | 0.8 | 0.01 | 0.001 | 0.007 | 0.004 | 0.004 | 0.4 | -- | 0.1 | 3.6 |
| $PM_{2.5}$ [5] | 128.9 | 99.7 | 12.3 | 14.5 | 0.8 | 0.01 | 0.001 | 0.007 | 0.004 | 0.004 | 0.4 | -- | 0.1 | 1.0 |
| $NH_3$ | 100.0 | 75.9 | 24.1 | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| $H_2S$ | 1.3 | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 1.3 | -- | -- |

Source: HECA Project

**Notes:**

[1] Total annual HRSG emissions represents the maximum emissions rate from a composite firing scenario (all three fuels)

[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% $PM_{2.5}$

CO = carbon monoxide
$CO_2$ = carbon dioxide
CTG = combustion turbine generator
$H_2S$ = hydrogen sulfide
$NH_3$ = ammonia
$NO_X$ = nitrogen oxides
$PM_{10}$ = particulate matter 10 microns in diameter
$PM_{2.5}$ = particulate matter 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal $PM_{10}$)
$SO_2$ = sulfur dioxide
VOC = volatile organic compounds

**Plant Startup Emissions**

This section describes a plant-wide "cold" startup. If the Project is being restarted after a short outage, where little or no maintenance is required, the durations of each step will be much shorter than indicated in the following description. This sequence assumes that all the necessary utility and support systems are already in service (plant distributed control system, fire protection and other safety systems, electrical switchyard and in-plant electrical distribution, water treatment, wastewater deep well injection, natural gas, steam, instrument and plant air, purge nitrogen, etc.).

The power block startup sequence on natural gas is similar to a conventional natural gas combined cycle plant. Once all the startup permissives are met, GE's Frame 7FB start signal is given and the gas turbine generator is used as a motor to rotate the gas turbine and accelerate it until the operation is self sustaining (static start). The gas turbine compressor is first partially loaded to provide enough air flow and duration to purge the HRSG. Following the purge, natural gas is introduced into the CTG combustors and the gas turbine operation becomes self sustaining and the static start is discontinued. When the gas turbine reaches 3,600 revolutions per minute (RPM), or "full speed, no load," it is synchronized with the electrical grid and the main breaker is closed. Shortly after the CTG is synchronized it is loaded to a minimum or "spinning reserve" load. All the preceding steps are executed automatically by the CTG's control computer. At this point the HRSG begins warming up and rapidly begins to produce steam. The steam is initially vented to the atmosphere and as pressure builds in the steam system the atmospheric vents close and the steam flow is diverted to the surface condenser.

Once dry steam is available the steam turbine startup sequence can be initiated. The steam turbine metal temperature determines how quickly the steam turbine can be loaded. If the steam turbine has been down for an extended period of time, it will follow the "cold start" sequence. The cold start sequence requires the CTG to operate at reduced load (below the emission compliance level) for up to 3 hours. During this time, the gas turbine load is slowly increased to match the steam temperature to the steam turbine metal temperature to heat the steam turbine while minimizing thermal stress. Once the gas turbine reaches the required load, steam is introduced to control $NO_x$ formation. Once the SCR catalyst reaches the required temperature, ammonia injection is initiated and the HRSG stack emissions will fall to the required compliance levels. The CTG can then be loaded normally to baseload and the steam turbine will reach a load based on the available steam. At this point the power block is producing more than enough power to support the rest of the Project.

The ASU will require about 4 days to start up and reach full capacity. Because the ASU operates at cryogenic conditions, the startup sequence includes an extensive cool down and drying period. During this time, the main air compressor and booster air compressor will be operated to provide the "auto refrigeration" necessary to cool and dry the ASU. Near the end of the startup sequence, the ASU will begin producing liquid oxygen and liquid nitrogen. The liquid oxygen is stored to provide a backup oxygen supply to cover a compressor trip or other short ASU outage. The liquid nitrogen storage is provided as a backup supply for the purge nitrogen system. Once the ASU is producing enough oxygen to operate at least one gasifier, the liquid oxygen pumping and vaporization system can be started to make high pressure $O_2$ vapor available to the gasification unit.

The AGR unit is assumed to be ready to start (purged with $N_2$ and with startup methanol levels established in the circulating system). Methanol circulation is started and the refrigeration system is started to begin cooling the methanol to normal operating temperature (approximately -40°F). This sequence is expected to take about 2 days and will complete at about the same time that sufficient $O_2$ is available to start a gasifier.

The SRU includes two conventional Claus reactor trains. Operation of the second Claus reactor train is not required if only one gasifier is operating, or if both gasifiers are operating on low sulfur coal/coke blends. This sequence assumes that both trains will be needed and that the first train is started up along with the single TGTU. The SRU reactor furnace is refractory lined. After an extended outage, both the refractory and the SRU catalyst require a gradual heating program that will take about 3 days. The heating is provided by firing natural gas with air in the reaction furnace. The combustion products flow through the reactor furnace, catalyst beds, and boilers to the tail gas thermal oxidizer. During the refractory dryout/cure period, the hydrogenation reactor in the TGTU will also be preheated. The hydrogenation reactor catalyst requires pre-sulfiding which will be timed to complete when the SRU is feed ready and the first gasifier is feed ready. At the end of this sequence, the amine circulation in the TGTU will be established and operating conditions will be established.

The gasifier vessels are refractory lined and require about 1 to 2 days to heat up to the temperature that allows $O_2$ and the feedstock to be introduced.

The shift reactors require warm-up and pre-sulfiding before sour syngas can be introduced. The shift reactor catalyst is heated by circulating hot nitrogen across the catalyst beds for about 2 days. The nitrogen is heated indirectly with a high pressure steam heater. Once the catalyst is hot, a small amount of sulfur-containing compound is added to the circulating $N_2$. The pre-sulfiding is completed when traces of sulfur are detected in the effluent of the second shift reactor. The shift reactors are then isolated hot and ready for feed.

The carbon dioxide compression system will be purged and ready to compress carbon dioxide. The carbon dioxide compressor startup sequence will be timed to coincide with the time the AGR is producing $CO_2$ in sufficient quantity to allow sustained operation of the carbon dioxide compressor.

When the gasifier refractory reaches operating temperature, the gasifier can be started by introducing oxygen and a sulfur-free feedstock, then switching to the petroleum coke and/or petroleum coke-coal blend feedstock. Raw syngas produced is sent to gasification flare until the system pressure and flow are stabilized. For normal start-up, the syngas sent to flare is essentially sulfur-free.

Syngas is diverted through the shift reactors and low-temperature gas cooling sections and then to AGR. The AGR unit solution will begin absorbing the carbon dioxide in the syngas. Once the carbon dioxide concentration in the “rich” solution reaches the required level, the flash drums will begin separating carbon dioxide vapor. This carbon dioxide will be washed to remove any traces of methanol and vented to the atmosphere at the top of the absorber column.

Once sufficient hydrogen-rich fuel production is available, GE’s Frame 7FB can initiate a switch either to co-firing or to 100 percent hydrogen-rich syngas. At this point the startup is complete and normal operation begins.

**Commissioning**
Commissioning will be completed by system with the utilities (power, water, natural gas, steam, etc.) completed first. In general, the major process units will be commissioned in a sequence that begins with the feed producing units and ends with the product producing units and systems.

The commissioning sequence will begin with the auxiliary CTG operating in commissioning mode for up to 356 hours. After this, the auxiliary CTG and auxiliary boiler will run in normal mode for 892 hours while the HRSG operates in commissioning mode on natural gas.

As described in Section 2.6.4, Commissioning, the major process units will be commissioned sequentially. The major gasification block units consume substantial amounts of electrical power. Therefore, the power block needs to be highly reliable and functioning on natural gas prior to commissioning on hydrogen-rich syngas. For this reason, the power block will be commissioned about 6 months ahead of the gasification block. The commissioning for the Project will require four distinct phases which are described as follows.

- Combined cycle unit commissioning on natural gas;
- Commissioning of the auxiliary simple cycle CTG on natural gas;
- Gasification block, including ASU, and balance of plant commissioning; and
- Commissioning the combined cycle unit on hydrogen-rich fuel.

The startup and commissioning period of the Project (CTG, ASU, process block and BOP, IGCC) is expected to be completed within one year from mechanical completion. Commercial operation will start when the commissioning and startup activities are completed and the licensor/contractor guarantees and milestones have been achieved. The ramp-up period to maturity is estimated to be 3 years from the start of commercial operation. The hydrogen-rich fuel availability for mature operation is estimated to be greater than 80 percent. The power availability for mature operation is estimated to be greater than 90 percent.

While considerable data exists on commissioning periods on power generation involving natural gas, and mature operation is reached within a few months for NGCC type systems, the power generation involving hydrogen-rich fuel from solid feedstock such as petroleum coke or coal requires a longer ramping duration due to the shakedown periods involved in the various technologies employed in the process block; in particular, the solid feedstock gasification. For this reason, the process block is expected to have an availability much less than 80 percent during the first 3 years.

After the one-year initial Startup and basic Commissioning Phase, there will be multiple gasifier starts per year. These will occur over the lifespan of the Project, and therefore, can be considered as part of the ‘normal’ operations of the Project, from an air quality standpoint. Consequently, these gasifier startup emissions from the gasification flare are no greater than the emissions from the gasification flare from normal gasifier start-ups. However, the frequency and duration of gasification flare operations are speculative. Although each individual unit and technology has been demonstrated, the integration of the technologies in this Project is unique. Therefore, total gasifier commissioning emissions are speculative.

**Combined Cycle Unit Commissioning on Natural Gas**

The natural gas commissioning procedure for the combined cycle unit (CTG/HRSG) is similar to that used for conventional natural gas fired combined cycle plants. The GE Frame 7FB uses diffusion combustors with steam injection, rather than dry-low $NO_x$ combustors, so the $NO_x$ tuning procedure is the primary difference between this Project and conventional natural gas fired combined cycle turbines. The following list briefly describes the steps for commissioning on natural gas:

- First fire
- Green rotor run-in
- Support of steam blows
- Initial steam turbine roll
- $NO_x$ tuning with steam injection
- Water wash and simple cycle CTG performance and emissions testing
- Duct burner testing
- Installation of SCR and oxidation catalyst
- Continuous emissions monitoring system (CEMS) drift test and source testing
- Combined cycle functional testing
- Water wash and combined cycle performance testing and continuous operation test

The emissions associated with the sequence above are shown in Table 5-10, Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas at 59°F.

The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. A maximum of 892 hours of operation during commissioning of the combustion turbine with partially abated emissions is expected over a period not to exceed 5 months. The annual frequency of turbine starts during the year when commissioning occurs is not expected to exceed the frequency of turbine starts during operation (see Table 5-10, Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas at 59°F). Fuel flow monitoring will be conducted for all tests.

## Table 5-10
## Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas at 59°F

| Test Phase | Hours of Operation | CTG Load | SCR/CO Status | $SO_X$ (lb) | $NO_X$ (lb) | CO (lb) | VOC (lb) | $PM_{10}$ (lb) |
|---|---|---|---|---|---|---|---|---|
| First Fire | 4 | FSNL | Not Operating | 4 | 232 | 8,800 | 1,380 | 72 |
| Green Rotor Run-In | 12 | 10% | Not Operating | 16 | 1,320 | 14,400 | 780 | 216 |
| Steam Blows | 168 | 30% | Not Operating | 365 | 57,960 | 8,400 | 1,680 | 3,024 |
| Restoration | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Initial Steam Turbine Roll | 24 | 10% | Not Operating | 31 | 2,640 | 28,800 | 1,560 | 432 |
| $NO_X$ Tuning with Steam Injection and initial STG loading | 16 | 60% | Not Operating | 44 | 1,936 | 936 | 54 | 288 |
| $NO_X$ Tuning with Steam Injection and initial STG loading | 16 | 100% | Not Operating | 59 | 2,688 | 1,282 | 75 | 288 |
| Finalize $NO_x$ Control Constants | 40 | 60% | Not Operating | 109 | 4,840 | 2,340 | 136 | 720 |
| Finalize $NO_x$ Control Constants | 40 | 80% | Not Operating | 129 | 5,800 | 2,732 | 160 | 720 |
| Finalize $NO_x$ Control Constants | 96 | 100% | Not Operating | 357 | 16,128 | 7,690 | 451 | 1,728 |
| CTG Water Wash and Contractor's Emission and Simple Cycle Performance Testing | 16 | 100% | Not Operating | 59 | 2,688 | 1,282 | 75 | 288 |
| Duct Burner Testing | 96 | 100% | Not Operating | 453 | 19,488 | 12,490 | 1,171 | 1,728 |
| Install SCR and Oxidation Catalyst | 24 | 100% | Testing | 89 | 4,032 | 1,922 | 113 | 432 |
| CEMS Drift and Source Testing | 64 | 100% | Operating | 238 | 2,157 | 1,312 | 301 | 1,152 |
| Functional Testing Demonstration Hours | 12 | Vario us | Operating | 10 | 500 | 5,560 | 920 | 100 |
| Functional Testing Steady State Hours | 48 | 100% | Operating | 178 | 1,618 | 984 | 226 | 864 |
| CTG Water Wash and Preparation for Performance Testing | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Combined Cycle Performance Testing | 24 | 100% | Operating | 113 | 1,054 | 641 | 180 | 432 |
| Continuous Operation Test | 192 | 100% | Operating | 713 | 6,470 | 3,936 | 902 | 3,456 |
| | **892** | | | **2,966** | **131,550** | **103,506** | **10,165** | **15,940** |
| | | | | **1.5** | **65.8** | **51.8** | **5.1** | **8.0** |

Source: HECA Project

**Notes:**

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

The gas turbine commissioning periods begin when the turbines first burn natural gas. The Applicant will make every effort to minimize emissions of CO, VOCs, and $NO_x$ during the commissioning period. However, not all of the equipment to abate these emissions will be fully operational at the start of the commissioning period. The Applicant requests a maximum of 552 hours of partially abated emissions for the gas turbine train.

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

Commissioning emissions were very conservatively estimated as worst case by assuming that the control efficiency of the applicable abatement systems is essentially zero during significant portions of the commissioning phase. Where applicable, emission offsets will be the mitigation of these emissions.

The CEMS will also be undergoing commissioning at this time. Once the CEMS is commissioned, it will record emissions of $NO_x$ and CO. Emissions of $SO_2$ and $PM_{10}$ may be quantified by using emission factors based on fuel flow.

**Combined Cycle Block Commissioning on Hydrogen Rich Syngas**

The combined cycle block will require additional testing and $NO_x$ tuning with hydrogen-rich syngas. The testing will cover the range of natural gas/hydrogen-rich syngas blends and allowable load ranges. The combined cycle block is assumed to have been commissioned first on natural gas. The oxidation catalysts are assumed to be in service and active when the HRSG operating temperature is sufficient. The SCR catalyst and ammonia injection system are assumed to be operating whenever the SCR catalyst temperature is in the required range and operation is sufficiently stable. Ammonia injection may be off-line during the initial phases of $NO_x$ tuning. The key activities and events that are expected to produce air emissions are listed below:

- Startup and shutdown of GE’s Frame 7FB on natural gas
- Standby operation of the combined cycle block on natural gas
- CTG $NO_x$ tuning on co-firing
- CTG $NO_x$ tuning on 100 percent hydrogen-rich syngas
- CTG $NO_x$ tuning on part load
- Water wash and performance testing on hydrogen-rich fuel
- Duct burner testing on hydrogen-rich syngas
- Source testing on hydrogen-rich fuel blends across the load range
- Functional testing including fuel transfers and load changes

- Plant-wide performance test
- Plant-wide operational reliability test

The emissions associated with the sequence above are shown in Table 5-11, Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen Rich-Syngas at 59°F.

The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. A maximum of 644 hours of operation during commissioning of the auxiliary combustion turbine with partially abated emissions is expected over a period not to exceed 5 months. The annual frequency of turbine starts during the year when commissioning occurs is not expected to exceed the frequency of turbine starts during operation. Fuel flow monitoring will be conducted for all tests.

**Table 5-11**
**Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen Rich-Syngas at 59°F**

| Test Phase | Hours of Operation | CTG Load | SCR/CO Status | $SO_X$ (lb) | $NO_X$ (lb) | CO (lb) | VOC (lb) | $PM_{10}$ (lb) |
|---|---|---|---|---|---|---|---|---|
| CTG Starts on Natural Gas | 30 | Various | Not Operating | 84 | 5,010 | 11,820 | 2,940 | 690 |
| CTG Fired Shutdowns | 30 | Various | Not Operating | 30 | 1,860 | 3,780 | 630 | 300 |
| CTG/HRSG Standby Operation on Natural Gas | 120 | 60% | Operating | 327 | 2,904 | 1,776 | 408 | 2,160 |
| CTG $NO_x$ Tuning @ 45% Hydrogen-Rich Syngas Co-firing | 16 | 100% | 50% SCR, 90% CO (*) | 49 | 1,584 | 692 | 88 | 576 |
| CTG $NO_x$ Tuning @ 90% Hydrogen-Rich Syngas Co-firing | 16 | 100% | 50% SCR, 90% CO (*) | 38 | 1,832 | 744 | 48 | 576 |
| CTG $NO_x$ Tuning @ 100% Hydrogen-Rich Fuel | 16 | 100% | 50% SCR, 90% CO (*) | 38 | 928 | 146 | 45 | 576 |
| CTG $NO_x$ Tuning @ 100% Hydrogen-Rich Fuel Min Load | 16 | 60% | 50% SCR, 90% CO (*) | 27 | 768 | 102 | 37 | 576 |
| CTG Water Wash and Contractor's Emission and Simple Cycle Performance Testing on Hydrogen-Rich Fuel | 24 | 100% | Operating | 57 | 1,106 | 403 | 77 | 864 |
| Duct Burner Testing on Hydrogen-Rich Syngas | 48 | 100% | Operating | 128 | 2,386 | 869 | 168 | 1,728 |
| Source Testing @ 100% Hydrogen-Rich Syngas | 16 | 100% | Operating | 38 | 738 | 269 | 51 | 576 |
| Source Testing @ 100% Hydrogen-Rich Syngas | 16 | 100% | Operating | 43 | 795 | 290 | 56 | 576 |

**Table 5-11**
**Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen Rich-Syngas at 59°F**

| Test Phase | Hours of Operation | CTG Load | SCR/CO Status | $SO_X$ (lb) | $NO_X$ (lb) | CO (lb) | VOC (lb) | $PM_{10}$ (lb) |
|---|---|---|---|---|---|---|---|---|
| Source Testing @ 45% Hydrogen-Rich Syngas Co-firing | 16 | 100% | Operating | 49 | 634 | 386 | 88 | 576 |
| Source Testing @ 90% Hydrogen-Rich Syngas Co-firing | 16 | 100% | Operating | 38 | 774 | 470 | 107 | 576 |
| Functional Testing Steady State Hours | 48 | 100% | Operating | 128 | 2,386 | 869 | 168 | 1,728 |
| CTG Water Wash and Preparation for Performance Testing | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| IGCC Performance Testing | 24 | 100% | Operating | 64 | 1,193 | 434 | 84 | 864 |
| Continuous Operation Test | 192 | 100% | Operating | 512 | 9,542 | 3,475 | 672 | 6,912 |
| **Notes: During weeks 44 though 53, none of the emissions overlap** | **644** | | | **1,650** | **34,440** | **26,525** | **5,667** | **19,854** |
| | | | | **0.8** | **17.2** | **13.3** | **2.8** | **9.9** |

Source: HECA Project

**Notes:**

| | | |
|---|---|---|
| CO | = | carbon monoxide |
| CTG | = | combustion turbine generator |
| HRSG | = | heat recovery steam generator |
| N/A | = | not applicable |
| $NO_X$ | = | nitrogen oxides |
| $PM_{10}$ | = | particulate matter 10 microns in diameter |
| SCR | = | selective catalytic reduction |
| $SO_X$ | = | sulfur oxides |
| VOC | = | volatile organic compound |

### Commissioning the Auxiliary Simple Cycle CTG on Natural Gas

The auxiliary simple cycle CTG (GE LMS100®) is exclusively fueled by natural gas and is provided with water injection for primary $NO_x$ control. The following list briefly describes the steps for commissioning on natural gas:

- First fire
- $NO_x$ tuning with water injection
- Installation of SCR and oxidation catalyst
- CEMS drift test and source testing
- Water wash and performance and functional testing

The emissions associated with the sequence above are shown in Table 5-12, Duration and Criteria Pollutant Emissions for Commissioning of the Auxiliary CTG on Natural Gas at 59°F.

The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. A maximum of 356 hours of operation during commissioning of the auxiliary combustion turbine with partially abated emissions is expected over a period not to exceed 5 months.

The gas turbine commissioning periods begin when the turbines first burn natural gas. The Applicant will make every effort to minimize emissions of CO, VOCs, and $NO_x$ during the commissioning period. However, not all of the equipment to abate these emissions will be fully operational at the start of the commissioning period. The Applicant requests a maximum of 236 hours of partially abated emissions for the gas turbine train.

**Table 5-12**
**Duration and Criteria Pollutant Emissions for Commissioning of the Auxiliary CTG on Natural Gas at 59°F**

| Test Phase | Hours of Operation | CTG Load | SCR/CO Status (3) | $SO_X$ (lb) | $NO_X$ (lb) | CO (lb) | VOC (lb) | $PM_{10}$ (lb) |
|---|---|---|---|---|---|---|---|---|
| First Fire | 4 | FSNL | Not Operating | 2 | 282 | 1,500 | 12 | 24 |
| $NO_X$ Tuning with Water Injection | 16 | 50% | Not Operating | 17 | 1,128 | 2,616 | 48 | 96 |
| $NO_X$ Tuning with Water Injection | 16 | 100% | Not Operating | 29 | 1,944 | 4,512 | 82 | 9696 |
| Finalize $NO_x$ Control Constants | 40 | 50% | Not Operating | 42 | 1,880 | 4,360 | 80 | 240 |
| Finalize $NO_x$ Control Constants | 40 | 75% | Not Operating | 57 | 2,600 | 5,960 | 108 | 240 |
| Finalize $NO_x$ Control Constants | 96 | 100% | Not Operating | 176 | 7,776 | 18,048 | 326 | 576 |
| Install SCR and Oxidation Catalyst | 24 | 100% | Testing | 44 | 1,944 | 4,512 | 82 | 144 |
| CEMS Drift and Source Testing | 64 | 100% | Operating | 117 | 531 | 762 | 147 | 384 |
| Functional Testing Steady State Hours | 48 | 100% | Operating | 88 | 398 | 571 | 110 | 288 |
| Preparation for Performance Testing | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Contract Performance Test | 8 | 100% | Operating | 15 | 66 | 95 | 18 | 48 |
| | **356** | | | **587** | **18,550** | **42,936** | **1,014** | **2,136** |
| | | | tons | **0.3** | **9.3** | **21.5** | **0.5** | **1.1** |

Source: HECA Project

**Notes:**

CO = carbon monoxide
CTG = combustion turbine generator
HRSG = heat recovery steam generator
N/A = not applicable
$NO_X$ = nitrogen oxides
$PM_{10}$ = particulate matter 10 microns in diameter
SCR = selective catalytic reduction
$SO_X$ = sulfur oxides
VOC = volatile organic compound

## 5.4 GREENHOUSE GAS EMISSIONS

California has enacted a law, Assembly Bill 32 (AB 32), to reduce greenhouse gas emissions to 1990 levels by 2020. Furthermore, California Governor Schwarzenegger's Executive Order S-3-05 sets a state target of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050. AB 32 requires the California Air Resources Board (CARB) to assign emissions targets to each sector in the California economy and to develop regulatory and market methods to ensure compliance, which take effect in 2012. The California Public Utilities Commission (CPUC) and CEC are to develop specific proposals to CARB for implementing AB 32 in the electricity sector, possibly including a cap-and-trade program. Senate Bill 1368 is a state regulation setting limits on greenhouse gas emissions from utilities.

Carbon dioxide emissions for the solid feedstock IGCC plant are 250 lbs/MWh on steady-state operations on syngas. The table included in Appendix B presents the peak or maximum possible carbon dioxide emissions for all Project emission sources. The annual average for steady-state operations of the IGCC, is expected to be less than 400 lbs/MWh, including emissions from typical natural gas co-firing, normal usage of natural gas, start-up, and shut-down. These steady-state emissions are approximately one-half of those from a typical natural gas combined cycle power plant. In summary, the Project's greenhouse gas emissions will be well below the 1,100 lbs/MWh threshold requirement (natural gas combined cycle comparison) of SB 1368.

## 5.5 MOBILE SOURCES

On-site truck trip emissions were incorporated in the dispersion modeling. Trucks delivering coal and coke feedstock would be traveling to the Project Site daily. In addition, trucks handling and storing gasification solids from the gasifiers would also be traveling around the Project Site on an hourly basis. The number of truck trips by period (e.g., hourly, daily, annual) is summarized in Table 5-13 below.

**Table 5-13**
**On-Site Truck Trips by Period**

| Period | Coke and Coal | On-Site Gasifier Solids Handling |
|---|---|---|
| 1 hour | 18 | 2 |
| 3 hours | 54 | 7 |
| 8 hours | 144 | 13 |
| 24 hours | 180 | 38 |
| Annual | 35,500 | 2,900 |

The feedstock trucks would enter the plant from Adohr Road on the north side, and then proceed to the truck unloading station north of the inactive feedstock storage. At the truck unloading area, each truck would idle for about 5 to 10 minutes while unloading, then loop back around through the truck scales and wash rack to exit the plant onto Adohr Road.

Typically, the gasification solids handling trucks would travel from the gasifiers, where they pick up the gasifier solids in containers, then drive offsite. Alternatively they may drive around to the gasifier solids storage area where they would off load the containers. The conservative assumption that they do not immediately leave was used in this analysis. These trucks would also travel at about 10 miles per hour. At the pick up and drop off points, trucks would idle for about five to 10 minutes. The distance traveled within the site for all trucks would be less than one mile.

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

EMFAC2007 emissions factors for calendar year 2015 were used for the dispersion modeling analysis. The anticipated Project start date is 2015, and the Project must show upon commencing operations that it will not violate PSD significance levels or ambient air quality standards for criteria pollutants. The EMFAC2007 2015 calendar year factors were used in the modeling of on-site trucks to demonstrate compliance with these standards. EMFAC2007 gram-per-mile factors from the model output and gram-per-second rates used in the AERMOD modeling are summarized in Table 5-14 below.

**Table 5-14**
**EMFAC2007 Heavy Truck Emission Factors and AERMOD Emission Rates**

| | **Emission Factors from EMFAC** | | | |
|---|---|---|---|---|
| | **Onsite Coke and Coal Trucks** | | **Onsite Gasifier Solids Handling Trucks** | |
| **Pollutant** | **Running (g/mi)** | **Idling (g/hr)** | **Running (g/mi)** | **Idling (g/hr)** |
| $NO_x$ | 16.59 | 115.98 | 23.65 | 115.98 |
| CO | 8.29 | 47.47 | 12.05 | 47.47 |
| SO2 | 0.03 | 0.06 | 0.04 | 0.06 |
| $PM_{10}$[a] | 1.09 | 1.12 | 1.47 | 1.12 |
| $PM_{2.5}$ | 0.79 | 1.03 | 1.14 | 1.03 |
| | **Emission Rates for AERMOD** | | | |
| | **Onsite Coke and Coal Trucks** | | **Onsite Gasifier Solids Handling Trucks** | |
| **Pollutant** | **Running (g/s)** | **Idling (g/s)** | **Running (g/s)** | **Idling (g/s)** |
| $NO_X$ | | | | |
| 1-hour | 0.080 | 0.068 | 0.007 | 0.005 |
| Annual | 0.018 | 0.015 | 0.001 | 0.001 |
| CO | | | | |
| 1-hour | 0.040 | 0.028 | 0.004 | 0.002 |
| 8-hour | 0.040 | 0.028 | 0.004 | 0.002 |

**Table 5-14**
**EMFAC2007 Heavy Truck Emission Factors and AERMOD Emission Rates**

| Pollutant | Emission Rates for AERMOD | | | |
|---|---|---|---|---|
| | Onsite Coke and Coal Trucks | | Onsite Gasifier Solids Handling Trucks | |
| | Running (g/s) | Idling (g/s) | Running (g/s) | Idling (g/s) |
| $SO_2$ | | | | |
| 1-hour | 1.4e-4 | 3.6e-5 | 1.2e-5 | 2.9e-6 |
| 3-hour | 1.4e-4 | 3.6e-5 | 1.4e-5 | 3.3e-6 |
| 24-hour | 6.0e-5 | 1.5e-5 | 9.1e-6 | 2.2e-6 |
| Annual | 3.3e-5 | 8.1e-6 | 1.9e-6 | 4.8e-7 |
| $PM_{10}$ | | | | |
| 24-hour | 0.002 | 2.7e-4 | 3.6e-4 | 4.0e-5 |
| Annual | 0.001 | 1.5e-4 | 7.7e-5 | 8.5e-6 |
| $PM_{2.5}$ | | | | |
| 24-hour | 0.002 | 2.5e-4 | 2.8e-4 | 3.7e-5 |
| Annual | 0.001 | 1.3e-4 | 6.0e-5 | 7.9e-6 |

**Notes:**
1. Includes tire wear, brake wear, and entrained road dust.

The purpose of the air quality impact analyses is to evaluate whether or not criteria pollutant emissions resulting from the Project will cause or contribute significantly to a violation of a California or national AAQS or contribute significantly to degradation of air quality-related values in Class I areas. Mathematical models, designed to simulate the atmospheric transport and dispersion of airborne pollutants, are used to quantify the maximum expected impacts of Project emissions for comparison with applicable regulatory criteria. The impacts from operations will be associated with the operation of the gasification block, power block, and ancillary equipment.

The air quality modeling methodology described in this section has been documented in a formal modeling protocol, which has been submitted for comment to CEC, SJVAPCD, and EPA Region 9. A copy of this protocol is provided in Appendix C. The modeling approaches used to assess various aspects of the Project's potential impacts to air quality are discussed below. The approaches discussed below follow the Modeling Protocol. Modeling of on-site mobile emissions was included in response to a comment by CEC during review of the Modeling Protocol. Copies of the modeling files are included on the digital versatile disks (DVD) entitled HECA Air Quality Modeling Files provided with this PSD application.

## 6.1 MODEL AND MODEL OPTION SELECTIONS

The impacts of Project operations on criteria pollutant concentrations in receptor areas within 31 miles (50 km) from the Project Site and Controlled Area were evaluated using the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) (Version 07026). AERMOD is appropriate for this Revised AFC because it has the ability to assess dispersion of emission plumes from multiple point, area, or volume sources in flat, simple, and complex terrain, and to use sequential hourly meteorological input data. The regulatory default options were used, including building and stack tip downwash, default wind speed profiles, exclusion of deposition and gravitational settling, consideration of buoyant plume rise, and complex terrain.

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

Note that emissions reduction credits will be obtained by the Applicant to offset Project emissions increases of the following pollutants: $NO_x$, VOC, $PM_{10}$, and $SO_2$. They are above the SJVAPCD emission offset triggering levels specified in the District's Rule 2201.4.5.3. The modeling did not take into account any reduction in emissions due to offsets.

Evaluation of commissioning and operational $NO_2$ concentrations (1-hour and annual averaging times) was accomplished using the OLM option in AERMOD. The OLM option accounts for the role of ambient $O_3$ in limiting the conversion of emitted $NO_x$ (which occurs mostly in the form of nitrogen oxides [NO]) to $NO_2$, the pollutant regulated by ambient standards. The input data to the AERMOD-OLM model includes representative hourly $O_3$ monitoring data for the years corresponding to the meteorological input record.

To evaluate whether urban or rural dispersion parameters should be used in model simulations, an analysis of land use adjacent to the Project Site was conducted in accordance with Section 8.2.8 of the *Guideline on Air Quality Models* (USEPA 2003) and Auer (1978),USEPA AERMOD implementation guide (2004), and its addendum (2006). Based on the Auer land use procedure, more than 50 percent of the area within a 1.9 mile (3 km) radius of the Project is classified as rural. Since the Auer classification scheme requires more than 50 percent of the area within the 1.9 mile (3 km) radius around a proposed new source to be non-rural for an urban classification, the rural mode will be used in the AERMOD modeling analyses. All regulatory default options will be used, including building and stack tip downwash, default wind speed profiles, exclusion of deposition and gravitational settling, consideration of buoyant plume rise, and complex terrain.

## 6.2 BUILDING WAKE EFFECTS

The effects of building wakes (i.e., downwash) on plumes from the Project's operational sources were evaluated in accordance with USEPA guidance (USEPA 1985). Data on the buildings on the Project Site that could potentially cause plume downwash effects for the sources were determined for different wind directions using the USEPA Building Profile Input Program – Prime (BPIP-Prime) (Version 98086) (USEPA 1995). Forty-two structures were identified within the Project Site to be included in the downwash analysis, including 21 buildings and 21 tanks. A table listing all the structures evaluated in the downwash analysis is included in Appendix D.

The results of the BPIP-Prime analysis were included in the AERMOD input files to enable downwash effects to be simulated. Input and output electronic files for the BPIP-Prime analysis are included with those from all other dispersion modeling analyses on the digital versatile discs (DVDs) that are being submitted with this Application.

## 6.3 METEOROLOGICAL DATA

Meteorological data suitable for direct input to AERMOD were obtained from the SJVAPCD website. Hourly surface data for calendar years 2000, 2001, 2002, 2003, and 2004 were obtained from the SJVAPCD at the Bakersfield Airport meteorological station which is located in the city of Bakersfield, within 20 miles (32.2 km) east-northeast of the Project Site. These data have been pre-processed by the SJVAPCD with the Oakland upper air data to create an input data set specifically tailored for input to AERMOD. The SJVAPCD prepared this data specifically for applicants use for locations such as HECA.

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

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

## 6.4 RECEPTOR LOCATIONS

The receptor grids used in the AERMOD modeling analyses for operational sources were as follows:

- 25-meter spacing along the fenceline and extending from the fenceline out to 100 meters beyond the Project Site and Controlled Area line
- 50-meter spacing from 100 to 250 meters beyond the Project Site and Controlled Area line
- 100-meter spacing from 250 to 500 meters beyond the Project Site and Controlled Area line
- 250-meter spacing from 500 meters to 1 km beyond the Project Site and Controlled Area line
- 500-meter spacing within 1 to 2 km of Project sources
- 1,000-meter spacing within 2 to 10 km of Project sources

Figure 6-1, Near-Field Model Receptor Grid and Figure 6-2, Far-Field Model Receptor Grid, show the placement of near-field and far-field receptor points, respectively. Terrain heights at receptor grid points were determined from U.S. Geological Survey digital elevation model files. During the refined modeling analysis for operational Project emissions, if a maximum predicted concentration for a particular pollutant and averaging time is located within the portion of the receptor grid with spacing greater than 25 meters, a supplemental dense receptor grid will be placed around the original maximum concentration point and the model will be rerun. The dense grid will use 25-meter spacing and will extend to the next grid point in all directions from the original point of maximum concentration.

Consistent with accepted practice, this AERMOD receptor grid, with the additional dense nested grid points, was determined to best balance the need to predict maximum pollutant concentrations and allow all operational modeling runs to be completed in less than 1 week.

Because construction emission sources release pollutants to the atmosphere from small equipment exhaust stacks or from soil disturbances at ground level, maximum predicted construction impacts for all pollutants and averaging times will occur within the first km from the Project Site boundary. Accordingly, only the portion of the above grid with 25-meter spacing out to a distance of 200 meters was used for the construction modeling.

The same receptor grid used in the criteria pollutant modeling for the operational Project will be used in the health risk assessment modeling, with additional receptors placed at all sensitive locations (e.g., schools, hospitals, etc.) out to 10 km (6 miles). Finally, discrete receptors will be placed at the locations of all nearby residences.

## 6.5 TURBINE IMPACT SCREENING MODELING

As described previously, a screening modeling analysis was performed to determine which CTG/HRSG operating mode and stack parameters produced worst-case off-site impacts (i.e., maximum ground level concentrations for each pollutant and averaging time). Only the emissions from the CTGs with and without duct firing and evaporative cooling were considered in this preliminary modeling step. The screening modeling used AERMOD, as described in the previous sections. Building wake information and the receptor grid described above were also used. All 5 years of meteorological data were used in the screening analysis.

The AERMOD model simulated natural gas combustion emissions from the 20-foot-diameter (6.10 meters), 213-foot-tall (65 meters) stack for the CTG/HRSG unit and the 16-foot diameter (4.88 meters), 110-foot tall (33.5 meters) auxiliary CTG unit. The stacks were modeled as point sources at their proposed locations within the Project Site. Table 6-1, Turbine Screening Results Normal Operations – Emissions and Stack Parameters per Turbine, summarizes the combustion CTG screening results for the different CTG operating load conditions. First, the model was run with unit emissions (1.0 grams per second) from each stack to obtain normalized concentrations that are not specific to any pollutant. CTG vendor data used to derive the stack parameters for the different operating conditions evaluated in this screening analysis are included in Appendix B.

The maximum ground level concentrations predicted to occur off site with unit turbine emission rates for each of the seven operating conditions shown in Table 6-1, Turbine Screening Results Normal Operations – Emissions and Stack Parameters per Turbine, were then multiplied by the corresponding turbine emission rates for specific pollutants. The highest resulting concentration values for each pollutant and averaging time were then identified (see bolded values in the table).

The stack parameters associated with these maximum predicted impacts were used in all subsequent simulations of the refined AERMOD analyses described in the next subsection. (Note that the lower exhaust temperatures and flow rates at reduced turbine loads correspond to reduced plume rise, in some cases resulting in higher off-site pollutant concentrations than the higher baseload emissions.) Model input and output files for the screening modeling analysis are included with those from all other modeling tasks on the Air Quality modeling DVD that is provided with this application.

### 6.5.1 1-Hour Startup Scenarios

The worst-case 1-hour $NO_2$ and CO impacts will occur during an hour with a startup, thus the results of the screening analysis were not used to determine the turbine stack parameters. The results in Table 6-1 indicate that maximum hourly $NO_2$ and CO concentrations during normal operations will occur with the stack parameters corresponding to 60 percent load. However, the magnitude of the emissions for both these pollutants during the worst-case 60 minutes of the turbine startup sequence will be higher than those during normal operations at any ambient temperature condition. Since a startup is a transition from non-operation to full-load operation, the stack exhaust velocity and temperature during most of this operation are lower than the values indicated as “worst-case” by the turbine screening modeling. Accordingly, modeling simulations were conducted to estimate the maximum 1-hour $NO_2$ and CO concentrations during a startup with reduced stack exhaust velocity and temperature.

**Table 6-1**
**Turbine Screening Results Normal Operations – Emissions and Stack Parameters per Turbine**

| **Case** | **Case 1A** | **Case 1B** | **Case 1C** | **Case 2A** | **Case 2B** | **Case 2C** | **Case 3** | **Case 4A** | **Case 4B** | **Case 4C** |
|---|---|---|---|---|---|---|---|---|---|---|
| **Scenario Description** | **HRSG Stack, Hydrogen-rich Fuel** | | | **HRSG Stack, Natural Gas Fuel** | | | **HRSG Stack Co-Firing** | **Auxiliary CTG** | | |
| HRSG/CTG Load Level | 100% Load | 80% Load | 60% Load | 100% Load | 80% Load | 60% Load | 100% Load | 100% Load | 75% Load | 50% Load |
| Stack Outlet Temperature (°F) | 200.0 | 190.0 | 180.0 | 180.0 | 170.0 | 160.0 | 190.0 | 740.0 | 740.0 | 760.0 |
| Stack Outlet Temperature (°K) | 366.48 | 360.93 | 355.37 | 355.37 | 349.82 | 344.26 | 360.93 | 666.48 | 666.48 | 677.59 |
| Stack Exit Velocity (ft/s) | 63.3 | 51.8 | 42.7 | 53.1 | 45.6 | 37.7 | 58.4 | 70.2 | 61.7 | 50.2 |
| Stack Exit Velocity (m/s) | 19.3 | 15.8 | 13 | 16.2 | 13.9 | 11.5 | 17.8 | 21.4 | 18.8 | 15.3 |
| $NO_X$ as $NO_2$ (lb/hr) | 166.7 | 166.7 | 166.7 | 166.7 | 166.7 | 166.7 | 166.7 | 20.6 | 20.6 | 20.6 |
| CO (lb/hr) | 1,679.4 | 1,679.4 | 1,679.4 | 1,679.4 | 1,679.4 | 1,679.4 | 1,679.4 | 69.0 | 69.0 | 69.0 |
| $SO_2$ (lb/hr) | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 8.7 | 2.4 | 2.4 | 2.4 |
| $PM_{10}$ (lb/hr) | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 35.7 | 10.3 | 10.3 | 10.3 |
| $NO_X$ (g/s) | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 2.6 | 2.6 | 2.6 |
| CO (g/s) | 211.6 | 211.6 | 211.6 | 211.6 | 211.6 | 211.6 | 211.6 | 8.7 | 8.7 | 8.7 |
| $SO_2$ (g/s) (based on 0.4 grains total S/100 scf) (grains of total sulfur per 100 standard cubic feet of gas) | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 0.3 | 0.3 | 0.3 |
| $PM_{10}$ (g/s) | 4.5 | 4.5 | 4.5 | 4.5 | 4.5 | 4.5 | 4.5 | 1.3 | 1.3 | 1.3 |
| **Model Results – Maximum X/Q concentration (μg/m³/[g/s]) predicted from AERMOD (all receptors)** | | | | | | | | | | |
| 1–hour | 3.682 | 4.114 | 4.483 | 4.191 | 4.668 | **6.536** | 3.966 | 3.250 | 3.655 | 4.530 |
| 3–hour [1] | 3.313 | 3.703 | 4.035 | 3.771 | 4.201 | **5.882** | 3.569 | 2.925 | 3.289 | 4.077 |
| 8–hour [1] | 2.577 | 2.880 | 3.138 | 2.933 | 3.268 | **4.575** | 2.776 | 2.275 | 2.558 | 3.171 |
| 24–hour [1] | 1.473 | 1.646 | 1.793 | 1.676 | 1.867 | **2.614** | 1.586 | 1.300 | 1.462 | 1.812 |
| annual [1] | 0.295 | 0.329 | 0.359 | 0.335 | 0.373 | **0.523** | 0.317 | 0.260 | 0.292 | 0.362 |
| **Maximum Concentration (μ g/m³) Predicted per Pollutant Normal Operations (all receptors)** | | | | | | | | | | |
| $NO_X$ 1 hour | 77.313 | 86.394 | 94.140 | 88.001 | 98.030 | | 83.280 | 8.450 | 9.502 | 11.779 |
| $NO_x$ annual | 6.185 | 6.911 | 7.531 | 7.040 | 7.842 | | 6.662 | 0.676 | 0.760 | 0.942 |
| CO 1 hour | 779.024 | 870.518 | 948.575 | 886.714 | 987.766 | | 839.142 | 28.276 | 31.795 | 39.414 |

## Table 6-1
## Turbine Screening Results Normal Operations – Emissions and Stack Parameters per Turbine

| Case | Case 1A | Case 1B | Case 1C | Case 2A | Case 2B | Case 2C | Case 3 | Case 4A | Case 4B | Case 4C |
|---|---|---|---|---|---|---|---|---|---|---|
| **Scenario Description** | **HRSG Stack, Hydrogen-rich Fuel** | | | **HRSG Stack, Natural Gas Fuel** | | | **HRSG Stack Co-Firing** | **Auxiliary CTG** | | |
| CO 8 hour | 545.317 | 609.363 | 664.003 | 620.700 | 691.436 | | 587.399 | 19.793 | 22.256 | 27.590 |
| $SO_2$ 1 hour | 4.050 | 4.525 | 4.931 | 4.610 | 5.135 | | 4.362 | 0.975 | 1.096 | 1.359 |
| $SO_2$ 3 hour | 3.645 | 4.073 | 4.438 | 4.149 | 4.621 | | 3.926 | 0.878 | 0.987 | 1.223 |
| $SO_2$ 24 hour | 1.620 | 1.810 | 1.972 | 1.844 | 2.054 | | 1.745 | 0.390 | 0.439 | 0.544 |
| $SO_2$ annual | 0.324 | 0.362 | 0.394 | 0.369 | 0.411 | | 0.349 | 0.078 | 0.088 | 0.109 |
| $PM_{10}$ 24 hour | 6.627 | 7.405 | 8.069 | 7.543 | 8.403 | | 7.138 | 1.690 | 1.900 | 2.356 |
| $PM_{10}$ annual | 1.325 | 1.481 | 1.614 | 1.509 | 1.681 | | 1.428 | 0.338 | 0.380 | 0.471 |
| | Case 1A | Case 1B | Case 1C | Case 2A | Case 2B | Case 2C | Case 3 | Case 4A | Case 4B | Case 4C |

Source: HECA Project

[1] Only 1-hour impacts were modeled. Impact concentrations for other averaging times were estimated with USEPA Screening Factors: 0.9 for a 3-hour avg. time, 0.7 for an 8-hour avg. time, 0.4 for a 24-hr avg. time, and 0.08 for an annual average.

**Notes:**

°F = degrees Fahrenheit
°K = degrees Kelvin
CO = carbon monoxide
CTG = combustion turbine generator
$\mu g/m^3$ = micrograms per cubic meter
g/s = grams per second
HRSG = heat recovery steam generator
$NO_2$ = nitrogen dioxide
$NO_X$ = nitrogen oxides
$PM_{10}$ = particulate matter 10 microns in diameter
SCR = selective catalytic reduction
$SO_2$ = sulfur dioxide

## 6.6 REFINED MODELING

A refined modeling analysis was performed to estimate off-site criteria pollutant impacts from operational emissions of the Project. The modeling was performed as described in the previous sections, using 5 years of hourly meteorological input data. The new Project 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 (see previous subsection). The maximum mass emission rates that will occur over any averaging time, whether during turbine startups, normal operations, turbine shutdowns, or a combination of these activities, were used in all refined modeling analyses (see Table 6-1). Emissions from the other sources were also included in the refined modeling runs. Emission rate calculations and assumptions used for all pollutants and averaging times are documented in Appendix B.

The DEGADIS model was used to calculate CO and $H_2S$ impacts from the carbon dioxide vent because the plume from the carbon dioxide vent is denser than air and could not be modeled with AERMOD. The DEGADIS model is a USEPA-approved screening model for dense gas plumes. As a screening model, it cannot use hourly meteorological data; it uses worst-case meteorology and can model 1-hour and 8-hour averaging times. The model calculates downwind concentrations until the plume centerline reaches ground level; at that point the model stops calculating concentrations. The SCREEN3 model was used to extend the then neutral density plume downwind to locations offsite when DEGADIS predicted a ground-level maximum within the Project Site and Controlled Area boundary. Model inputs and CO and $H_2S$ emission rates are summarized in Table 6-2, DEGADIS Model Inputs and Parameters, below.

**Table 6-2**
**DEGADIS Model Inputs and Parameters**

| Max Value at Exit of Stack | 100% Flow |
|---|---:|
| Molecular Weight of vent gas | 44.0 |
| Flow, pounds/hour | 656,000 |
| Flow, kilograms/second | 82.656 |
| Temp, F | 65 |
| Temp, K | 291.6 |
| Stack diameter, inches | 42 |
| Stack diameter, meters | 1.067 |
| Stack height, feet | 260 |
| Stack height, meters | 79.3 |
| $H_2S$ Concentration (ppm) | 10 |
| $H_2S$ Emission Rate (lb/hr) | 5.15 |
| CO Concentration (ppm) | 1,000 |
| CO Emission Rate (lb/hr) | 418.5 |
| Stability Class | D |
| Wind speed, meters | 1 |

Source: HECA Project

**Notes:**

CO = carbon monoxide
F = Fahrenheit
K = Kelvin
$H_2S$ = hydrogen sulfide

### 6.6.1 Fumigation Analysis

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

A fumigation analysis was performed using SCREEN3 to calculate concentrations from inversion breakup fumigation. A unit emission rate was used (1 gram per second) in the fumigation modeling to obtain a maximum unit concentration (x/Q), and the model results were scaled to reflect expected Project emissions for each pollutant. Inversion breakup fumigation concentrations were calculated for 1- and 3-hour averaging times using USEPA-approved conversion factors. These multiple-hour model predictions are conservative, since inversion breakup fumigation is a transitory condition that would most likely affect a given receptor location for only a few minutes at a time.

Since SCREEN3 only models the impacts from one source, the model was run for each combustion source: the CTG/HRSG unit, auxiliary CTG, tail gas thermal oxidizer, and gasifier refractory heater. To calculate the inversion breakup fumigation, the default thermal internal boundary layer factor of 6 in the SCREEN3 model was used.

Fumigation impacts were determined for each source, then summed over all sources using peak predicted fumigation concentrations regardless of location. Since fumigation impacts can affect concentrations longer than 1 hour, the procedures described in Section 4.5.3 of "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources" (USEPA 1992) were used to determine the 3- and 8-hour average concentrations.

## 6.7 COMPLIANCE WITH AMBIENT AIR QUALITY STANDARDS

Air dispersion modeling was performed according to the methodology described in above This was done to evaluate the maximum increase in ground level pollutant concentrations resulting from Project emissions, and to compare the maximum predicted impacts, including background pollutant levels, with applicable short-term and long-term CAAQS and NAAQS. The impacts from construction activities and operations were analyzed separately because they will occur during different time periods. The same 5-year record of hourly meteorological data described in Section 6.3 was used in the AERMOD modeling to evaluate both construction and operational impacts.

In evaluating both construction and operational impacts, AERMOD was used to predict the increases in criteria pollutant concentrations at all receptor locations due to Project emissions only. Next, the maximum modeled incremental increases for each pollutant and averaging time were added to the maximum background concentrations, based on air quality data collected at the most representative monitoring stations during the last 3 years (i.e., 2006 through 2008). These background concentrations are presented and discussed in Section 3.2, Existing Air Quality. The resulting total pollutant concentrations were then compared with the most stringent CAAQS or NAAQS.

As described previously, the emissions used in the AERMOD simulations for the Project operations were selected to ensure that the maximum potential impacts will be addressed for each pollutant and averaging time corresponding to an AAQS. The emissions used for each pollutant and averaging time are explained and quantified in Section 5.1.2.2, Operational Emissions. This subsection describes the maximum predicted operational impacts of the Project for normal combined cycle operating conditions. Commissioning impacts, which will occur on a temporary, one-time basis and will not be representative of normal operations, were addressed separately, as described in the next subsection.

Table 6-3, 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 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 SJVAB is designated non-attainment with respect to the federal ambient standards. No SILs have been established yet for $PM_{2.5}$.

Table 6-3, AERMOD Modeling Results for Project Operations (All Project Sources Combined), also shows that the modeled impacts due to the Project emissions, in combination with conservative background concentrations, will not cause a violation of any AAQS 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.

The locations of predicted maximum impacts will vary by pollutant and averaging time. Figure 6-3, Locations of Maximum Predicted Ground Level Pollutant Concentrations for the Operational Project Area, shows the locations of the maximum predicted operational impacts for all pollutants and averaging times. The peak 24-hour $PM_{10}$ and $PM_{2.5}$ concentrations are predicted to occur on the western boundary of the Project Site, while the peak annual $PM_{10}$, $PM_{2.5}$, $SO_2$, and $NO_x$ concentrations are predicted to occur on the southern boundary of the Project Site. The peak $SO_2$ 1- and 3-hour concentrations, peak CO 1- and 8-hour concentrations, and peak $NO_x$ 1-hour concentration are predicted to occur within approximately 1.5 miles south of the Project Site.

Carbon monoxide impacts from the carbon dioxide vent were predicted to be 2,934 µg/m 3 at a point off of the Project Site and Controlled Area at 778 meters from the source. This value is below the CAAQS for CO and below the 8-hour CO SIL, but above the 1-hour CO SIL. A stability class of D combined with one meter per second wind speed was found to calculate the worst-case results. The 1-hour CO SIL exceedence is not significant because the ensuing AAQS evaluation estimated total estimated CO levels at less than 20 percent of the applicable AAQS and there are no PSD increments for CO.

Hydrogen sulfide impacts from the carbon dioxide vent were predicted to be 35.84 µg/m$^3$ at the maximum impact point off of the Project Site and Controlled Area at 778 meters from the source. This value is below the 1-hour CAAQS of 42 µg/m$^3$.

## Table 6-3
## AERMOD Modeling Results for Project Operations (All Project Sources Combined)

| Pollutant | Averaging Period | 2000 | 2001 | 2002 | 2003 | 2004 | Max | Class II Significance Level | % of SIL | Background Conc. [5] | Monitoring Station Description[5] | CAAQS | NAAQS | Total Conc. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | | (μg/m$^3$) | | (μg/m3) | (μg/m3) | (μg/m$^3$) |
| $NO_2$ [1] | 1-hour (OLM) [1,6] | 96.84 | 97.45 | 100.50 | 96.28 | 97.07 | **100.50** | NA | NA | 190.1 | 1 | 339 | NA | 291 |
| | Annual (OLM) [1] | 0.83 | 0.87 | 0.82 | 0.87 | 0.79 | **0.87** | 1 | 87% | 39.6 | 1 | 57 | 100 | 40 |
| CO [3] | 1-hour [6] | 1231.13 | 1133.15 | 1422.59 | 1053.30 | 1091.04 | **1422.59** | 2,000 | 71% | 4025 | 2 | 23,000 | 40000 | 5448 |
| | 8-hour [6] | 213.28 | 169.18 | 187.52 | 181.40 | 151.98 | **213.28** | 500 | 43% | 2444 | 2 | 10,000 | 10000 | 2657 |
| $SO_2$ | 1-hour [6] | 21.46 | 16.81 | 21.45 | 16.55 | 19.95 | **21.46** | NA | NA | 340.6 | 3 | 655 | NA | 362 |
| | 3-hour [6] | 7.84 | 6.24 | 7.15 | 7.31 | 7.11 | **7.84** | 25 | 31% | 195 | 3 | NA | 1300 | 203 |
| | 24-hour [6] | 0.62 | 0.65 | 0.50 | 0.66 | 0.91 | **0.91** | 5 | 18% | 81.38 | 3 | 105 | 365 | 82 |
| | Annual | 0.13 | 0.13 | 0.13 | 0.14 | 0.14 | **0.14** | 1 | 14% | 26.7 | 3 | NA | 80 | 27 |
| PM10 | 24-hour [6] | 2.56 | 2.39 | 2.90 | 2.64 | 2.58 | **2.90** | 5 | 58% | 267.4 | 4 | 50 | 150 | - |
| | Annual | 0.53 | 0.53 | 0.56 | 0.58 | 0.59 | **0.59** | 1 | 59% | 56.5 | 4 | 20 | Revoked | - |
| PM2.5 [4] | 24-hour [6] | 1.65 | 1.63 | 1.74 | 1.67 | 2.22 | **2.22** | 5 | 44% | 154 | 5 | NA | 35 | - |
| | Annual | 0.41 | 0.41 | 0.43 | 0.44 | 0.45 | **0.45** | 1 | 45% | 25.2 | 5 | 12 | 15 | - |
| $H_2S$ [7] | 1-hour | 35.84 | 35.84 | 35.84 | 35.84 | 35.84 | **35.84** | NA | NA | NA | NA | 42 | NA | 35.84 |

Source: HECA Project

**Notes:**

[1] Ozone Limiting Method (OLM) was applied using hourly $O_3$ data.

[3] $CO_2$ Vent was not included in the AERMOD analysis; it was modeled using DEGADIS/SCREEN3, which predicted maximum impacts of 2,934 μg/m$^3$ for the 1-hour average. The current assumption is that only one gasifier heater is expected to be operational at any time. Aux Boiler does not operate with HRSG at the same time for short -term average period. Therefore, the Aux Boiler was not included in the modeling analysis while HRSG was included because HRSG gives more impact on off-Project Site and Controlled Area concentration.

[5] 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

**Table 6-3**
**AERMOD Modeling Results for Project Operations (All Project Sources Combined)**

| Pollutant | Averaging Period | 2000 | 2001 | 2002 | 2003 | 2004 | Max | Class II Significance Level | % of SIL | Background Conc. [5] | Monitoring Station Description[5] | CAAQS | NAAQS | Total Conc. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | (μg/m$^3$) | | (μg/m$^3$) | | (μg/m3) | (μg/m3) | (μg/m$^3$) |

[6] 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 only one gasifier heater is expected to be operational at any one time.

[7] $H_2S$ was modeled using DEGADIS (its only source is the $CO_2$ vent). DEGADIS is a screening model that uses worst-case meteorology rather than actual monitored hourly meteorological data.

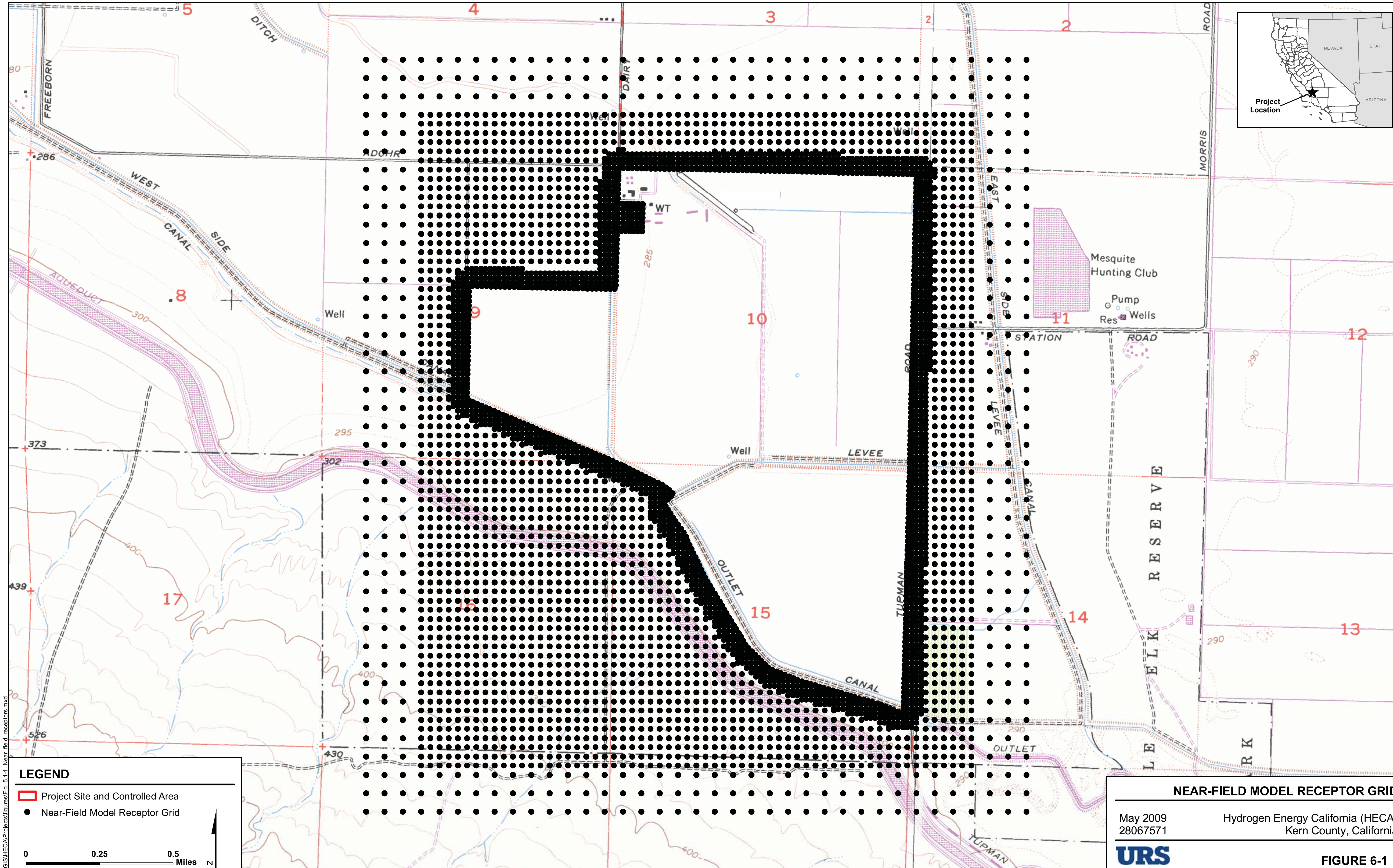
| | | | | | |
|---|---|---|---|---|---|
| μg/m$^3$ | = | micrograms per cubic meter | $NO_2$ | = | nitrogen dioxide |
| CAAQS | = | California Ambient Air Quality Standard | OLM | = | ozone limiting method |
| CO | = | carbon monoxide | $PM_{10}$ | = | particulate matter less than 10 microns in diameter |
| $H_2S$ | = | hydrogen sulfide | $PM_{2.5}$ | = | particulate matter less than 2.5 microns in diameter |
| NAAQS | = | National Ambient Air Quality Standard | $SO_2$ | = | sulfur dioxide |

## 6.8 COMPLIANCE WITH PSD INCREMENTS

Federal PSD regulations require that proposed major sources, such as HECA, as well as other sources constructed since a specified "baseline date," not contribute to air pollution in excess of PSD increments in criteria pollutant attainment areas. These PSD increments and significant impact levels are presented in Table 6-2. To implement PSD, attainment areas are divided into Class I and Class II areas. Class I areas, such as formally designated wilderness areas, national parks, and national monuments, are protected by the most stringent (i.e., smallest) PSD increments. In addition, Class I areas are protected by visibility standards (discussed in Section 7.0). All other non-Class I areas within attainment areas are considered to be Class II areas and are protected by the less-stringent Class II PSD increments.

The Project is located within a Class II area. The nearest Class I area is the San Rafael Wilderness, located approximately 50 km from the Project site. PSD is only applicable to those criteria pollutants that are currently in attainment of the NAAQS in Kern County: $NO_x$, CO, $PM_{10}$, and $SO_2$. Project emissions trigger PSD review for $NO_x$, CO, and $PM_{10}$. The PSD requirements are not applicable to those criteria pollutants that are currently in non-attainment.

The Project's maximum modeled air impacts for CO are 1,422 $\mu g/m^3$ (1-hour average) and 213 $\mu g/m^3$ (8-hour average), and the modeled impacts for $NO_2$ are 0.87 $\mu g/m^3$. The modeled impacts for $PM_{10}$ are 2.9 $\mu g/m^3$ (24-hour average) and 0.59 $\mu g/m^3$ (annual). As shown in Table 6-3, these impacts are well below the respective ambient impact levels. Because the HECA $NO_x$ and $PM_{10}$ impacts will be less than the SILs, increment consumption will be insignificant and no preconstruction monitoring or additional impact analyses are required. There are no PSD increments for CO. The Project's VOC emissions do not trigger PSD review for VOC.




NEAR-FIELD MODEL RECEPTOR GRID

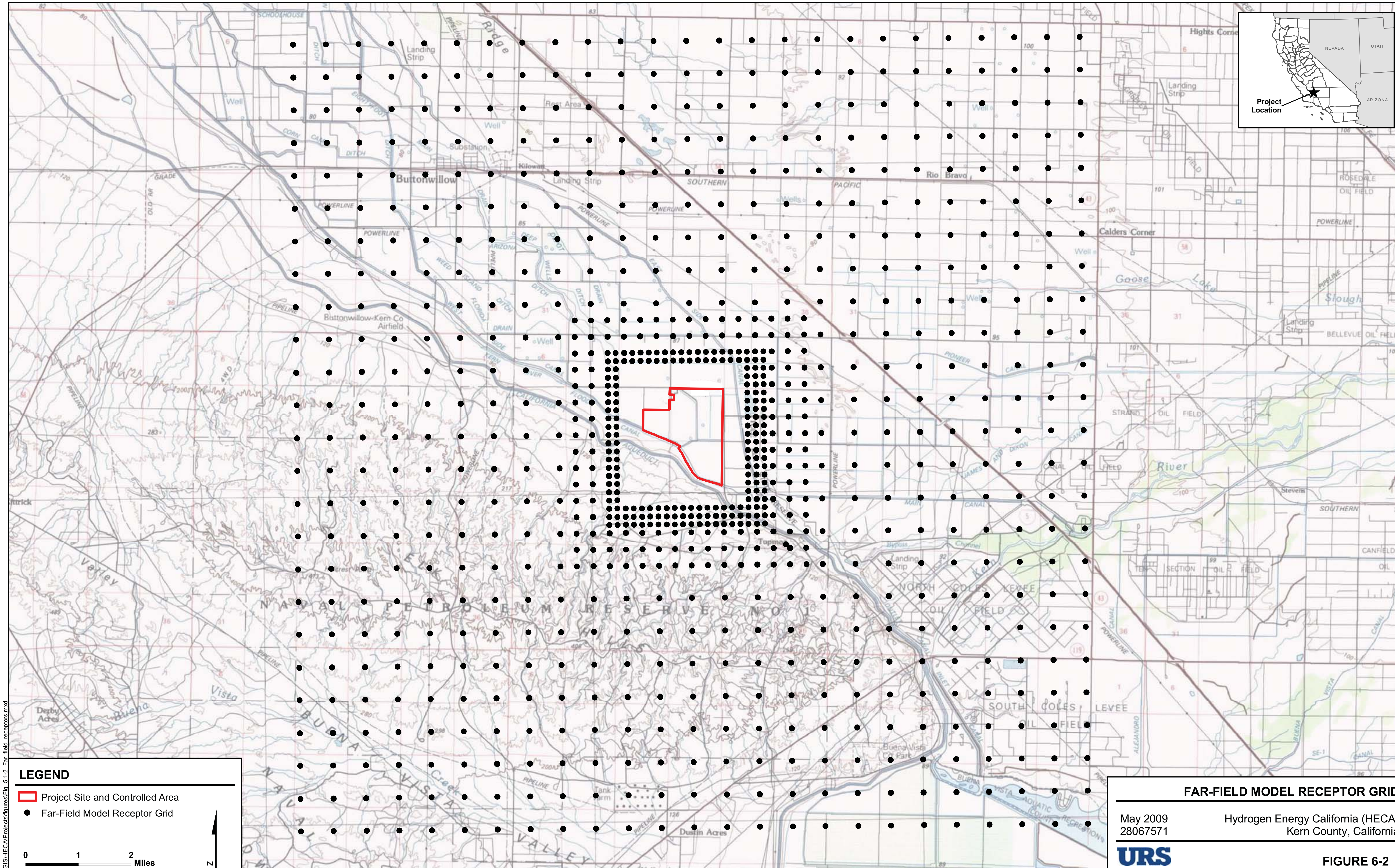
May 2009
28067571

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 6-1

Sources: USGS (7.5' quads: Taft 1982, Delano 1982). Created using TOPO!, ©2006 National Geographic Maps, All Rights Reserved. Kern County and State of California (proposed and approved projects).




**FAR-FIELD MODEL RECEPTOR GRID**

May 2009
28067571

Hydrogen Energy California (HECA)
Kern County, California

URS

**FIGURE 6-2**

Sources: USGS (30' x 60' quads: Taft 1982, Delano 1982). Created using TOPO!, ©2006 National Geographic Maps, All Rights Reserved. Kern County and State of California (proposed and approved projects).

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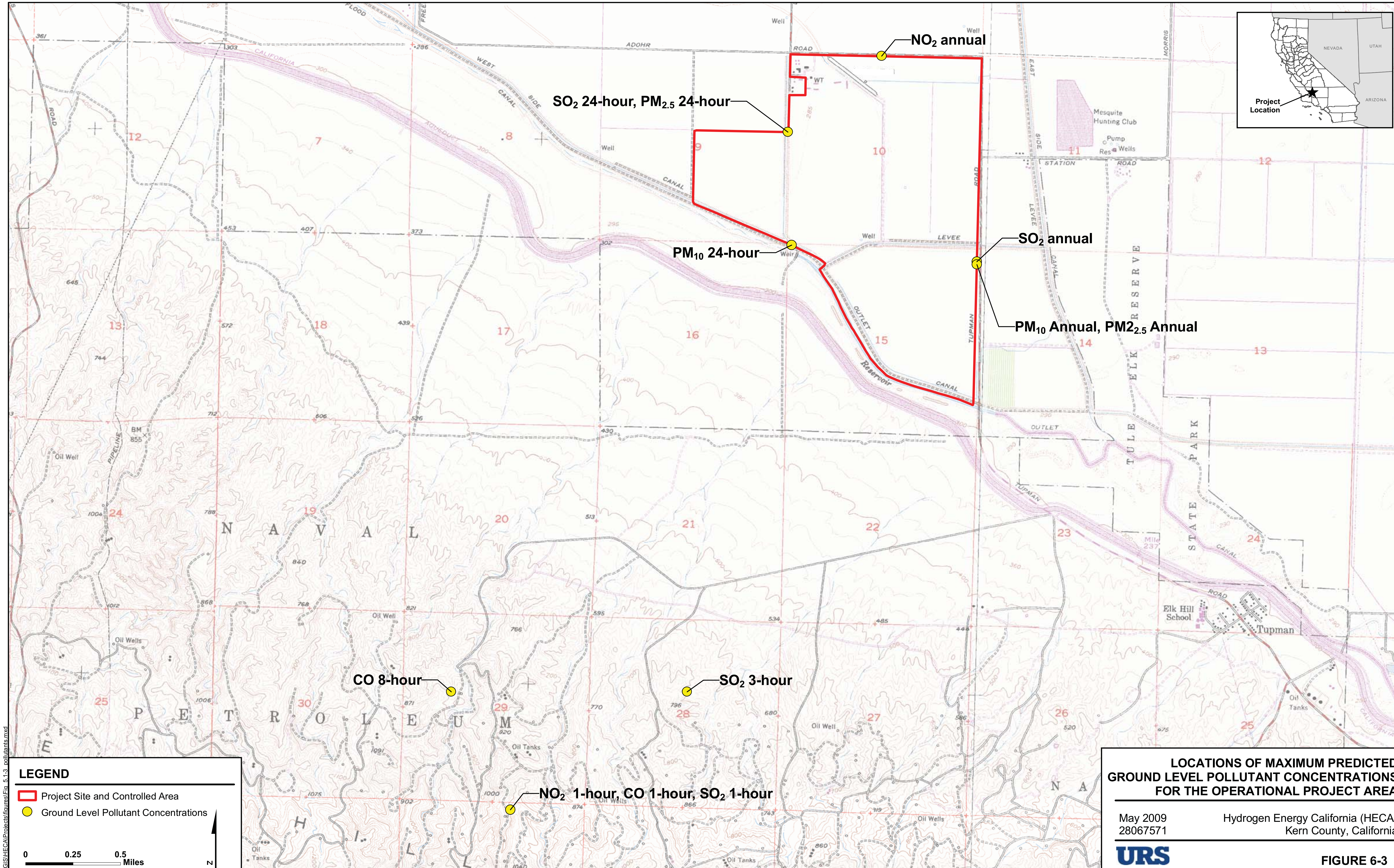


## LEGEND

- Project Site and Controlled Area
- Ground Level Pollutant Concentrations

0 0.25 0.5 Miles

N

**LOCATIONS OF MAXIMUM PREDICTED GROUND LEVEL POLLUTANT CONCENTRATIONS FOR THE OPERATIONAL PROJECT AREA**

May 2009
28067571

Hydrogen Energy California (HECA)
Kern County, California

URS

**FIGURE 6-3**

Sources: USGS (7.5' quads: Taft 1982, Delano 1982). Created using TOPO!, ©2006 National Geographic Maps, All Rights Reserved. Kern County and State of California (proposed and approved projects).

## 7.1 AIR QUALITY RELATED VALUES

### 7.1.1 Class I Areas

Specific national parks, wilderness areas, and national monuments are designated as Class I areas and are protected by the most stringent PSD requirements. A Major Source must evaluate impacts to visibility and other AQRV at all Class I areas that are located within a 100-km radius of the Project Site. All pollutants for which Project emissions are above the Major Source threshold (in this case, 100 tons per year [tpy]) and all pollutants for which emissions are above the PSD Significant Emissions Rates must be evaluated.

An evaluation of potential impacts in Class I areas within 62.1 miles (100 km) of the Project Site was conducted, because the Project's potential emissions increases of some pollutants are large enough to be considered a Major Source, thus triggering the federal PSD program. This section summarizes the dispersion models and modeling techniques that were used in performing the Class I area air quality analyses. A complete description of the modeling performed in support of the impacts to Class I areas is contained in Appendix E. The objectives of the modeling are 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.

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. However, Dome Land Wilderness Area and Sequoia National Park are greater than 62.1 miles (100 km) from the Project Site. Therefore, these two Class I areas do not meet the criterion of being within 62.1 miles (100 km) and will not be included in this analysis. The nearest 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 this Class I area and only far-field AQRV analyses were completed. PSD increment analysis for the San Rafael Wilderness Class I area are shown in Table 7-1, PSD Class I Increment Significance Analysis – CALPUFF Results. No Class I PSD increments will be exceeded.

**Table 7-1**
**PSD Class I Increment Significance Analysis – CALPUFF Results**

| | **Pollutant** | **Annual $NO_x$** | **3-hour $SO_2$** | **24-hour $SO_2$** | **Annual $SO_2$** | **24-hour Particulate Matter** | **Annual Particulate Matter** |
|---|---|---|---|---|---|---|---|
| | **Unit** | **µg/m³** | **µg/m³** | **µg/m³** | **µg/m³** | **µg/m³** | **Annual** |
| **Class I Area** | **Threshold** | **0.1** | **1** | **0.2** | **0.08** | **0.32** | **0.16** |
| San Rafael Wilderness Area | 2001 | 3.98E-03 | 2.37E-01 | 1.17E-02 | 8.23E-04 | 7.72E-02 | 4.38E-03 |
| | 2002 | 4.58E-03 | 2.70E-01 | 1.75E-02 | 9.99E-04 | 7.97E-02 | 5.20E-03 |
| | 2003 | 4.60E-03 | 3.13E-01 | 1.81E-02 | 9.97E-04 | 7.43E-02 | 5.12E-03 |
| Exceed? | | No | No | No | No | No | No |

Source: HECA Project
$\mu g/m^3$ = micrograms per cubic meter
$NO_x$ = nitrogen oxides
$SO_2$ = sulfur dioxide

**Effects on Visibility**. The Clean Air Act (CAA) established the importance of visibility for Class I areas by declaring a goal to prevent future visibility impairment and remedy existing visibility impairment due to man-made air pollution. The CAA also specifically requires that visibility be addressed as an AQRV within all Class I areas. However, visibility is not uniformly affected by air pollution. Visibility varies on a site-by-site basis and is affected by meteorology, topography, the relative position of the viewer and the sun, and other variables. In addition, the assessment of visibility depends on subjective human perceptions. As a result, it is often difficult to assess the condition of the visibility AQRV.

This analysis was conducted using the CALPUFF model. Applicable recommendations from the CALPUFF Reviewer's Guide (Draft) of September 2005 prepared for the National Park Service (NPS) and the USFS were implemented in the screening version of CALPUFF AQRV modeling.

Using weather from a 3-year meteorological data set developed using a combination of surface station and mesoscale meteorological (MM5) data for 2001-2003 in CALPUFF resulted in no days per year with 5 percent extinction change. Visibility impact results for the San Rafael Wilderness Class I area are shown in Table 7-2, Visibility Analysis – CALPUFF Results. No maximum extinction change exceeds 5 percent. Therefore, the Project screening successfully passed all screening criteria.

**Table 7-2**
**Visibility Analysis – CALPUFF Results**

| Class I Area | Pollutant | No. of Days > 5% | Maximum Extinction Change | Day of Maximum Extinction Change |
|---|---|---|---|---|
| | **Unit** | **Days** | **%** | **Day** |
| | **Threshold** | **0** | **5** | |
| San Rafael Wilderness Area | 2001 | 0 | 4.42 | 308 |
| | 2002 | 0 | 4.72 | 287 |
| | 2003 | 0 | 3.68 | 247 |
| Exceed? | | No | No | No |

Source: HECA Project

**Terrestrial Resources.** Maximum modeled annual $NO_2$ and $SO_2$ impacts from normal plant operations, as well as estimates of total nitrogen and sulfur deposition estimated by CALPUFF, were compared against Deposition Analysis Threshold (DAT) for individual sources established by the NPS for vegetation and ecosystems for Class I Wilderness Areas. Table 7-3, Total Nitrogen and Sulfur Deposition Analysis – CALPUFF Results, summarizes the maximum modeled impacts versus the NPS and the USFS significance criteria. All impacts are below the significance criteria.

**Table 7-3**
**Total Nitrogen and Sulfur Deposition Analysis – CALPUFF Results**

| | Pollutant | Deposition Nitrogen | Deposition Sulfur |
|---|---|---|---|
| | Unit | $g/m^2/s$ | $g/m^2/s$ |
| Class I Area | Threshold | 1.59E-11 | 1.59E-11 |
| San Rafael Wilderness Area | 2001 | 1.06E-12 | 4.41E-13 |
| | 2002 | 1.40E-12 | 6.00E-13 |
| | 2003 | 1.34E-12 | 5.23E-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 (ANC) and pH, and, therefore, acidification or eutrophication, are not likely to occur.

### 7.1.2 Class II Areas

The PSD regulations (40 CFR 52 §52.21(o)) require an Additional Impact Analysis for all PSD major modifications for Class II areas. The additional impact analysis is an evaluation of the following:

- the visibility impact for the surrounding area that results from the general growth associated with the modification.
- visible plumes
- the impairment to visibility, soils, and vegetation that would result from the modification; and

The Project complies with the requirements of 40 CFR 52.21. The Project should not result in any significant commercial, residential, or industrial growth within Kern County. Additionally, the Project should not cause any impairment to the visibility, soils, or vegetation within the surrounding area of Kern County.

#### *7.1.2.1 Surrounding Area Visibility Analysis*

A visibility analysis was performed for the area that surrounds the Project Site. Since little or no growth (i.e., municipal, residential, commercial and industrial) is expected from the Project, the visibility assessment focused on the significant emission increases from the Project. EPA's VISCREEN model (Version 1.01) was used to conduct the analysis. The approach is expected to provide a conservative estimate of the Project's impact on visibility in the surrounding Class II area.

The VISCREEN model is designed to ascertain whether the plume from a facility has the potential to be perceptible to an untrained observer under “reasonable worst-case” conditions. The model measures the change in perceptibility of a plume due to an increase in emissions as a function of contrast and color changes at different values of the scattering angle (angle between direct solar radiation and the line of sight). The green contrast value (Cp) was developed as a measure of the perceived reduction in contrast. The color difference parameter ($\Delta E$) was developed to specify the perceived magnitude of brightness and color changes due to a plume.

The VISCREEN model performs four tests that are based upon the Tier I screening criteria for $\Delta E$ and Cp (2.0 and 0.05, respectively). The first two tests refer to visual impacts caused by plume parcels located inside the boundaries of a given area. The last two tests refer to visual impacts caused by plume parcels located outside the boundaries of a given area. For internal and external visibility assessments, the two tests assess the perceptibility of the plume in relation to two plume-viewing backgrounds (i.e., the horizon sky and a black terrain object). When the potential for impacts in Tier I analysis is greater than the screening criteria, a Tier II screening procedure should be conducted, as described in the *Plume Visual Impact Screening Workbook* (EPA, 1988 and 1992).

The VISCREEN analysis incorporated a Nitrogen Oxides ($NO_x$) emission rate of 16.6072 g/s and a Particulate Matter ($PM_{10}$) emission rate of 4.7538 g/s. The $NO_x$ and $PM_{10}$ emission rate represents the post-Project, 24-hour PTE for all emission sources that are affected by the Project. A target background visual range distance of 25 km was used for the area surrounding the HECA facility (EPA, 1992). The distance between the Project and observer in the VISCREEN model was set equal to 25 km. The default background ozone concentration of 0.04 ppm was used.

Reasonable worst-case conditions are based upon meteorological data and observer distance. The Tier I screening approach uses worst-case meteorological conditions (i.e., extremely stable (stability category F) atmospheric conditions, low wind speed (1 m/sec) persisting for 12 hours, and wind direction that would transport the plume directly adjacent to the observer.

The Tier II analysis refined the default wind speed and stability category with site-specific information from the Bakersfield Regional Airport meteorological station (NWS 23840). This data set was first analyzed to determine the frequency of various combinations of wind speed and stability in all wind direction sectors that would carry the HECA facility plume toward nearby Class II areas located at 25 km from the HECA site. The frequency distributions were developed separately for four diurnal time periods (midnight-6:00 am, 6:00 am-noon, noon-6:00 pm, and 6:00 pm-midnight). For each time period, five wind speed categories corresponding to 0-1 meters per second (m/s), 1-2 m/s, 2-3 m/s, 3-4 m/s, and 4-5 m/s were analyzed for each of six stability classes (Class A-most unstable through Class F-most stable, Class G is considered as Class F) and wind direction compass sector toward the Class I area from the Project Site. For each time of day, 14 wind speed/stability combinations were ranked in order of increasing values of the dispersion parameter, $\sigma_z u$ as described above. The combinations include F stability for wind speed classes 1 through 4, E stability with wind speed classes 1 through 5, and D stability with wind speed classes 1 through 5, as per the Tier II guidance. Note that the lowest values of this parameter correspond to the most restrictive dispersion conditions. Finally, a table was constructed showing the percent frequency of occurrence for each combination of stability and wind speed or, alternatively for each value of $\sigma_z u$. These data are tabulated in terms of the frequency of each combination, as well as the cumulative frequency of all combinations with lower values of $\sigma_z$ u.

The meteorological condition for 25 km distant-Class II area with a cumulative frequency of 1 or greater, and with a wind speed fast enough to transport the plume to the given Class II area within 12 hours was selected. Based upon 2000-2004 meteorological data, the wind speed and stability class when the sum of all frequencies of occurrence of conditions worse than the conditions totals 1 percent is 1.5 m/s and the stability category was F. Table 7-4 presents the results of the Tier II screening analysis for the Project. The Delta E values were below the default screening threshold values. Therefore, visibility impacts caused by emissions from the Project will not be perceptible to most individuals in the area surrounding the Project.

**Table 7-4**
**Class II Surrounding Area Level II VISCREEN Results**

| **Maximum Visual Impacts INSIDE Area<br>Screening Criteria ARE NOT Exceeded** | | | | | |
|---|---|---|---|---|---|
| | | **Delta E** | | **Contrast** | |
| **Background** | **Theta** | **Plume** | **Critical Value** | **Plume** | **Critical Value** |
| SKY | 10 | 1.306 | 2.00 | 0.003 | 0.05 |
| SKY | 140 | 0.427 | 2.00 | -0.008 | 0.05 |
| TERRAIN | 10 | 0.514 | 2.00 | 0.007 | 0.05 |
| TERRAIN | 140 | 0.111 | 2.00 | 0.005 | 0.05 |
| **Maximum Visual Impacts OUTSIDE Area<br>Screening Criteria ARE NOT Exceeded** | | | | | |
| | | **Delta E** | | **Contrast** | |
| **Background** | **Theta** | **Plume** | **Critical Value** | **Plume** | **Critical Value** |
| SKY | 10 | 1.359 | 2.00 | 0.004 | 0.05 |
| SKY | 140 | 0.429 | 2.00 | -0.008 | 0.05 |
| TERRAIN | 10 | 0.857 | 2.00 | 0.009 | 0.05 |
| TERRAIN | 140 | 0.241 | 2.00 | 0.009 | 0.05 |

#### *7.1.2.2 Visible Plumes*

Modern combined cycle power plants burning natural gas fuel emit particulate matter at levels far below the concentration corresponding to visible smoke. Combustion sources also emit water vapor that sometimes may condense in the atmosphere to form visible plumes.

The potential exists for vapor plumes (water vapor condensation) to be visible from two sources at the Project Site: (1) plumes from the 50-foot-high wet cooling towers (4-celled ASU cooling tower and 17-celled Power Block/Gasification cooling towers); and (2) plumes from the 213-foot-high CTG/HRSG stack. Both sources of condensed water vapor plumes were analyzed. The following analysis describes the plume modeling methodology, input data, and assumptions used in the analysis, as well as the results.

**Methodology**

The frequency, persistence, and size of visible condensate plumes depends primarily on the design and type of combustion turbine generator/HRSG and/or cooling tower, as well as meteorological conditions of temperature and humidity. Specifically, visible plume formation depends on local ambient temperature, humidity conditions, and wind patterns. A location with higher temperature and lower humidity (i.e., general climate in Kern County) would have fewer extended visible plumes compared to operation of the same project at a cooler, more humid location. Visible plume formation is more frequent during the cooler seasons (i.e., winter) when ambient conditions are more conducive to plume formation. Results focused on seasonal daylight clear hours and winter day-time no fog hours. For the purposes of this analysis, **Seasonal Daylight Clear Hours** are defined as: daylight hours from November through April without naturally occurring fog, rain, or limited visibility and include all hours of clear skies and 50 percent of the scattered or broken skies. **Winter Day-Time No Fog Hours** are defined as winter days without any naturally occurring fog. It should be noted that the same ambient conditions that result in plume formation from Project cooling towers will often cause natural weather conditions such as fog, haze, and precipitation to occur, which generally reduces visibility. Days when fog, haze or precipitation is present were excluded from plume frequency calculations for this analysis.

The characteristics of visible plumes important to an assessment of visual impacts include plume length (the distance over which a plume remains intact), plume height (the distance from ground to the centerline of the plume), plume width (the horizontal cross wind spread of the plume) and plume depth (the cross plume spread perpendicular to the width, typically in the vertical direction).

Plumes from the wet cooling towers were modeled using the Seasonal/Annual Cooling Tower Impact (SACTI) model. SACTI is a mathematical model used to predict cooling tower visible plume dimensions over a full range of meteorological conditions experienced at a given location and the frequency of different plume lengths, widths, and heights as a function of direction from the cooling tower. The model is designed to provide predictions and may be used for the licensing of power plants with cooling towers. SACTI model results are summarized in terms of typical and reasonable worst-case visible plume dimensions for the entire year, and during daytime and nighttime hours. For purposes of this analysis, the “typical” plume dimension (height, width, length) is the one that is exceeded 50 percent of the time, and the “reasonable worst-case” is the condition that is exceeded only 10 percent of the time. A description of this model, model data inputs, and model results may be found in Appendix C, Modeling Protocol.

Plumes from the HRSG stack were analyzed using the Combustion Source Visible Plume (CSVP) model. The CSVP model determines visible water vapor plume frequency. The model consists of a series of programs, which ultimately calculate the distance downwind the visible plume can extend, the plume height and width. The model requires ambient temperature, relative humidity, precipitation, wind direction, wind speed and stability per hour of input data. The model was originally created to determine plume size for HRSGs. The first module of the program, CSVP, determines if the plume will reach saturation, and the second module, PLUMEWW, determines plume size by modeling the plume until the centerline of the plume crosses the second intersection point on the saturation curve. Parameters used in the model included the fixed HRSG stack height and diameter at 213 feet and 20 feet respectively. A description of this model, model data inputs, and model results may be found in Appendix C, Modeling Protocol.

**Model Results**

As stated above, visible plume formation is more frequent during the cooler seasons (i.e., winter) when ambient conditions are more favorable to plume formation. Therefore, Table 7-5, displays the dimensions of the "reasonable worst-case" plumes from both the Power Block/Gasification and ASU cooling towers predicted to be visible during clear winter day-time hours, when the plumes will be most noticeable. In addition, the dimensions of the typical (or average) daytime plumes from Project cooling towers are also provided in the table below. Typical plumes generated from Project cooling towers were predicted to be much smaller in length, height and width than the worst-case plumes. Visible plumes that extend beyond the cooling tower buildings are predicted to occur approximately 15 to 22% of the winter day-time no fog hours.

**Table 7-5**
**SACTI Cooling Tower Plume Predictions**
**Winter Day-Time No Fog Hours (Mass Flow Rate = 11554.9 kg/s)**

| | Power Block/ Gasification Cooling Tower | ASU Cooling Tower |
|---|---|---|
| Length (m)<br>50% (Typical)<br>10% (Reasonable Worst-case) | 30m – 40m<br>600m – 700m | 30m – 40m<br>200m – 250m |
| Height (m)<br>50% (Typical)<br>10% (Reasonable Worst-case) | 20m - 30m<br>300m – 310m | 20m – 30m<br>90m – 100m |
| Width (m)<br>50% (Typical)<br>10% (Reasonable Worst-case) | 30m – 40m<br>130m – 140m | 20m – 30m<br>60m – 70m |
| % of hours Visible Plume Extends Beyond Cooling Tower Building (greater than 30 meters from center) | 15.53% | 21.64% |

Source: SACTI Model Output (provided in Appendix C, Modeling Protocol)

**Notes:**

m = meters

Winter Day-Time No Fog Hours = Clear winter days, when a cold, high humidity conditions conducive to plume formation exists.

Similar to the results of the SACTI model, the results presented in Table 7-6, provided below, represents the reasonable worst-case (the 10% longest plume), and the typical plume expected (the 50% longest plume). The results depict only the hours that the plumes are visible in seasonal daylight clear conditions.

The reasonable worst-case visible plume predicted by the CSVP model has a plume height of 271.4 meters (890 feet); however, the average height of the visible plume was predicted to be 152.8 meters (501 feet) during seasonal daylight clear hours. Visible plumes are predicted to occur approximately 78% of the seasonal daylight clear hours; however are predicted to occur only 40% of all hours modeled.

**Table 7-6**
**CSVP HRSG Stack Plume Characteristics During Seasonal Daylight Clear Hours**

| | Plume Length (m) | Plume Height (m) | Plume Width (m) | Plume Depth (m) |
|---|---|---|---|---|
| Reasonable Worst Case (10%) | 716 | 271.4 | 84.9 | 75.6 |
| Typical Case (50%) | 197 | 152.8 | 34.5 | 39.1 |

Source: CSVP Model Output (provided in Appendix C, Modeling Protocol)

**Notes:**

m = meters

Seasonal Daylight Clear Hours = daylight hours from November through April without rain, fog, or limited visibility that include clear skies and 50 percent of the scattered or broken skies excluding overcast skies.

### Impact Analysis

Plumes generated from Project operations would be visible from residences and travelers within the VSOI. When plumes are formed over the Project Site they will be above and extend downwind of the Project structures.

The reasonable worst-case winter day-time no fog cooling tower plume height starts above the 50 foot (15.2m) Power Block/Gasification and ASU cooling towers and can reach an ultimate height of approximately 1,017 feet (310m) and 328 feet (100m), respectively. However, this worst case scenario is predicted to occur during just 10 percent of the winter day-time no fog hours in the 5 years modeled. Visible plumes lengths are not expected to extend beyond the Power Block/Gasification and ASU cooling towers structures more than 15.5 percent and 21.6 percent during all modeled winter day-time no fog hours.

The reasonable worst-case seasonal daylight clear HRSG plume height starts above the 213 foot (65m) HRSG stack and can reach an ultimate height of approximately 890 feet (271.4m) and is visible for approximately 764 feet (233m) downwind of the stack. However, this scenario is predicted to occur for only 15-25 percent of the seasonal daylight clear hours in the 5 years modeled. The model predicts some type of visible plume from the HRSG stack for 40% of all modeled hours (day, night, and all weather and sky conditions).

Plumes are expected to be visually subordinate from distant viewpoints, and subordinate to co-dominant from middleground to foreground viewpoints, depending upon specific viewing locations and conditions. Currently there are few to no visible plumes within the existing viewshed. Although the addition of plumes to the Project Area would create a change to existing conditions, most viewers will be at such distances that impacts from visible plumes are considered to be less than significant. The area of highest concern for visible plumes is for the nearest resident within the VSOI, represented by KOP #2.

For KOP #2, reasonable worst case visible plumes generated from Project operations would create a co-dominant effect related to the Project structures. However, typical plumes generated from Project operations were predicted to be much smaller in length, height and width than the reasonable worst-case plumes, and the typical plumes are what KOP #2 and other viewers within the VSOI would see more often.

Project operations would largely be in peak operation during the summer months (outside of the November to April seasonal hours), at which time the temperature at the Project Site is generally too high for long plumes to occur. Both size and frequency of typical Project cooling tower and HRSG plumes (occurring outside of the winter/no fog and seasonal daylight clear period) are expected to be visually subordinate and would be less than significant. Project cooling tower and HRSG plumes during the reasonable worst case (within the winter/no fog and seasonal daylight clear period) conditions would be visually co-dominant to dominant, however plumes of this size would occur for less than 10 percent of the winter/no fog and seasonal daylight clear period and were thus considered to be less than significant. As plume formation depends upon highly variable atmospheric conditions, peak operation of HECA would be during hot, summer months not conducive to plume formation, and the proximity of most viewers would be at such distances that any potential plumes would be remotely visible, less than significant impacts related to plume generation at the Project Site are anticipated.

Nighttime plumes could present a potential visual impact under two possible circumstances. If bright upwardly directed night lighting were to illuminate the plumes, they could become visually dominant and obtrusive. However, no such light exists in the Project vicinity and on-site lighting would be shielded and directed downward. Thus, no significant impacts from illuminated plumes are anticipated.

#### *7.1.2.3 Soils and Vegetation Analyses*

The soil type in the area of the HECA is dominantly Lokern-Buttonwillow, and the soil types of in the surrounding area of the HECA are Cajon-Westhaven, Elkhills, Garces-Panoche, Kimberlina-Wasco, and Milham. These soils are characterized as follows:

- Lokern-Buttonwillow is a deep, nearly level, somewhat poorly drained clay. This unit is used for native and irrigated pasture, irrigated crops, wildlife habitat, and some urban development. The saline-alkali condition of the soils, restricted permeability, and fine texture are the main limitations.
- Cajon-Westhaven is a deep, nearly level and gently sloping, well drained and somewhat excessively drained loamy sand and fine sandy loam. This unit is mainly used for irrigated crops. Low available water capacity and a hazard of soil blowing are the main limitation.
- Elkhills is a deep, rolling to steep, well drained soils that formed in mixed, stratified alluvium. Most areas of this unit are used as rangeland. Oil wells are common on the unit. Steepness of slope and a hazard of erosion are the main limitations.
- Garces-Panoche is a deep, nearly level, saline-alkali, well drained silt loam and clay loam. This unit is mainly used for irrigated crops and pasture. The saline-alkali condition of the soils and very slow permeability are the main limitations.
- Kimberlina-Wasco is deep, nearly level, well drained fine sandy loam and sandy loam. This unit is mainly used for irrigated crops.
- Milham is deep, nearly level, well drained sandy loam. This unit is mainly used for irrigated crops (USDA, 2009)

In general, soils are mainly affected through the leaching of particulate contaminates and through the removal of gases by precipitation followed by surface deposition. The adsorption rate is dependent on the distance from the source, the concentration of pollutant, soil properties, hydrological situations, and meteorological conditions. The dominant area soil types noted above are expected to exhibit a relatively low sorption capacity, as demonstrated by generally slow permeability, for the PSD significant emission rate increases in CO, $NO_x$, $PM_{10}$, $SO_2$, and VOC emissions associated with the Project. Also, the PSD modeling concentration results are below the NAAQS (since the concentration is compliance with the significance level); that are designed to protect health and welfare from any known or anticipated adverse pollutant impacts. Therefore, the soils in the area of the Project should not be adversely affected as a result of the Project.

The predominate food crops grown in the Kern County are wheat, corn, barley, cotton, and beans. Predicted average acreage yields are 96.5 bushels per acre of wheat; 182 bushel per acre of corn; 1,540 pounds per acre of cotton; and 2,552 pounds per acre of beans (USDA, 2009).

The direct effects of $NO_x$ on vegetation are usually associated with and confined to areas near specific industrial sources. For example, vegetation injury from exposure to $NO_2$ has been observed near nitric acid factories and arsenals, but there is little published information regarding vegetation injury in the field due to NO or other $NO_x$ (U.S. EPA, 1982).

Many reports, however, have substantiated $NO_x$ effects on vegetation grown in laboratory conditions. In vivo experiments performed by Hill and Bennet (1970) showed that both NO and $NO_2$ inhibit apparent photosynthesis of oat (*Avena sativa*) and alfalfa (*Medicago sativa*) plants at concentrations below those that caused visible foliar injury. They found the threshold does for this inhibition was 740 $\mu g/m^3$ for NO and 1130 $\mu g/m^3$ for $NO_2$ in 90-minute fumigations. Other researchers have found a reduction in the photosynthetic rate of tomato (*Lycopersicon esculentum*) exposed to 470 $\mu g/m^3$ $NO_2$ and 310 $\mu g/m^3$ NO. The effect of the two gases in combination had an additive inhibitive effect on photosynthesis.

Czeh and Nothdruft (1951) fumigated a wide range of agricultural and horticultural crops with $NO_2$ in the laboratory and small greenhouses. Rape (*Brassica rapus*), wheat (*Triticum aestivum*), oats (*Avena sativa*), peas (*Pisum sp.*), potatoes (*Solanum tuberosum*), and beans (*Phaseolus vulgaris*) showed little or no injury from 564 $\mu g/m^3$ $NO_2$ for one hour of exposure. Taylor and Cardiff (cited in Taylor et al., 1975) exposed field crop to No2 in sunlight chambers. Several field crops exposed to 18,880 $\mu g/m^3$ $NO_2$ for 90 minutes showed little or no injury, but in tomato, a 90-minute exposure to 28,200 $\mu g/m^3$ increased the extent of injury by 90 percent. The authors concluded that the injury threshold for several field crops would be 18,800 to 28,200 $\mu g/m^3$ $NO_2$ for 90-minute exposures.

The effect of $NO_x$ on several eastern forest tree species has been documented by Kress (1982). Two of the seven tree species ha exposed, Virginia pine (*Pinus virginiana*) and Loblolly pine (*Pinus taeda*), exhibited significant height growth effects in response to NO2 administered at 191 $\mu g/m^3$.

A threshold value of 191 $\mu g/m^3$ for long-term (10,000-hour) laboratory exposures of crops and trees has been widely used (U.S. EPA, 1982). The maximum modeled concentration from the Project is compliance with the National Ambient Air Quality Standard (NAAQS) (since the concentration is compliance with the significance level); therefore, no detrimental effects on vegetation in the Project area will likely result from $NO_x$ emissions from the Project.

There are very few data on the effects of S compounds on mature trees or other native plants (USDA, 1992). Data on tree seedlings (Hogsett and others 1989, cited in USDA, 1992) indicated that $SO_2$ concentrations below 20 ppb (52.29 $\mu g/m^3$) (24-hour mean) do not produce visible injury symptoms. According to *Guidelines for evaluation air pollution impacts on Class I wilderness areas in California* (USDA, 1992), maximum $SO_2$ concentrations should not exceed 40-50 ppb (104.6 $\mu g/m^3$– 130.7 $\mu g/m^3$) (24-hour mean), and annual average $SO_2$ concentration should not exceed 8-12 ppb (20.9 $\mu g/m^3$– 31.4 $\mu g/m^3$) in order to maximize protection of all plant species. The $SO_2$ PSD modeling concentration results are below the NAAQS (since the concentration is compliance with the significance level); that are designed to protect health and welfare from any known or anticipated adverse pollutant impacts. Therefore, the vegetation in the surrounding area should not be adversely affected by the $SO_2$ emission increase occurring with the Project.

Particulate matter less than 10 microns ($PM_{10}$) emissions are not harmful to vegetation unless the emissions are either highly caustic or the emission rate is great enough for heavy particulate deposits to occur. The $PM_{10}$ emissions from the Project are neither classified as caustic nor will the increase due to the Project exceed the $PM_{10}$ significance modeling thresholds. Thus, the $PM_{10}$ emissions are not considered a dangerous threat to the local vegetation.

Little is known regarding the effects of CO on vegetation, but some response may occur at levels approaching 1000 ppm (1.15 x $10^6$ $\mu g/m^3$) for a week or more. The maximum 1-hour CO concentration resulting from the Project is predicted to be well below this level; therefore, no significant impact on local vegetation from the CO emission increase is expected.

#### *7.1.2.4 Growth Induced Impacts*

There are no changes to the land uses or zoning designations surrounding the area of the Project Site. The existing character of the immediate area surrounding the Project Site will remain unchanged by the development of the Project. Construction of the Project would require approximately 1,500 employees. The Project will require 100 full-time employees working at the power plant during operation. It is anticipated that approximately 60 percent of operations employees will originate from the Kern County labor force. The remaining employees will originate from outside Kern County. Of the 40 percent non-local workers (40 workers), it is assumed for the purposes of this analysis that half (20 employees) will relocate to Kern County. The other half (20 employees) will commute on a daily or weekly basis. The Project's impacts with regard to land use planning and public policy will be minimal. The use of the 315-acre Project Site will change from mineral and petroleum defined land uses to power generation. No prime farmlands will be converted to non-agricultural use.

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# Appendix A

# BACT Analysis

# APPENDIX A

# BEST AVAILABLE CONTROL TECHNOLOGY (BACT) SECTION

# HECA POWER PROJECT
# KERN COUNTY, CALIFORNIA

*Prepared For:*

San Joaquin Valley Air Pollution Control District

California Energy Commission

U.S. Environmental Protection Agency Region IX

*Prepared on behalf of*

**Hydrogen Energy International LLC**

June 2009

URS

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## 1.0 APPLICABLE REGULATIONS

Federal requirements pertaining to control of pollutants subject to PSD review (i.e., attainment pollutants) were promulgated by U.S. EPA in 40 Code of Federal Regulations (CFR) 42.21 (j). This regulation defines Best Available Control Technology (BACT) as emission limits "based on the maximum degree of reduction for each pollutant." BACT determinations are made on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs.

Federal requirements pertaining to control of non-attainment pollutants, or Lowest Achievable Emission Rate (LAER), were promulgated by USEPA under 40 CFR 51.165 (a). This regulation defines LAER as the emissions limit based on either (1) the most stringent emission rate contained in a State Implementation Plan (SIP), unless the [source] demonstrates the rate is not achievable; or (2) the most stringent emissions limitation that is achieved in practice. The federal LAER does not consider the cost impacts of control.

BACT must be applied to any new or modified source resulting in an emissions increase exceeding any San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT threshold. SJVAPCD Rule 2201 requires HECA to apply BACT to any source that has an increase in emissions of oxides of nitrogen ($NO_{x)}$, volatile organic compounds (VOC), sulfur dioxide ($SO_2$), carbon monoxide (CO), and particulate matter equal to or less than 10 microns in diameter ($PM_{10)}$ (criteria pollutants) in excess of 2.0 pounds per highest day. BACT for the applicable pollutants was determined by reviewing the SJVAPCD BACT Guidelines Manual, the South Coast Air Quality Management District BACT Guidelines Manual, the most recent Compilation of California BACT Determinations, CAPCOA (2nd Ed., November 1993), and USEPA's BACT/LAER Clearinghouse.

BACT review is required for the proposed Project because the proposed Project will result in a significant net emissions increase for $NO_x$, CO, VOC, $PM_{10}$, and $SO_2$.

The basis for the emissions-related analyses is annual average operation at a design capacity of nominally 250 megawatts. The proposed Project as currently configured will involve the following major processes and emission units:

- One hydrogen-rich fuel and/or natural-gas–fired Combustion Turbine Generator (CTG) with Heat Recovery Steam Generator (HRSG) and one Steam Turbine-Generator (STG);
- One Natural-Gas – fired Simple-Cycle Auxiliary CTG
- One Multi-cell, Mechanical-draft Cooling Tower for the combined-cycle power block
- One Multi-cell, Mechanical-draft Cooling Tower for the Air Separation Unit
- One Multi-cell, Mechanical-draft Cooling Tower for the gasification block
- One Auxiliary Boiler
- Solid Feedstock Receiving and Handling System
- Gasification Block, including an Elevated Gasification Flare
- Three Natural-Gas – Fired Gasifier Warming (Refractory Heaters)

- Sulfur Recovery System (Tail Gas Thermal Oxidizer and two elevated flares with natural gas assist)
- Two Emergency, Diesel-Engine — Driven Generators
- One Diesel-Engine – Driven Fire – Water Pump
- One carbon dioxide ($CO_2$) vent stack

Section 2 of the revised AFC provides a complete description of the Project indicating the layout of the major plant components within the site, and general discussion of the project components.

## 2.0 BACT REVIEW PROCESS

BACT is defined in the PSD regulations as:

*"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs" [40 CFR 52.21(b)(12)]*

In a December 1, 1987 memorandum from the USEPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration, and the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps, described below (from the USEPA's Draft New Source Review Workshop Manual, 1990)[1]:

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

Step 2. Eliminate all technically infeasible control technologies;

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;

Step 4. Evaluate most effective controls and document results; and

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

[1] "New Source Review Workshop Manual," DRAFT October 1990, USEPA Office of Air Quality Planning and Standards

Formal use of these steps is not always necessary. However, the USEPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which USEPA believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies, i.e., those that provide the "maximum degree of emissions reduction."

Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each source. These options were identified by researching the USEPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in USEPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. An available technology is one that is commercially available, meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench-scale or laboratory testing;
- Pilot-scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams' physical and chemical characteristics.

For this BACT analysis, the available control options were identified by querying the USEPA RBLC and by consulting available literature on control options for integrated gasification combined cycle (IGCC). The analysis also involves review of currently permitted and operating IGCC facilities.

## 3.0 PROJECT SOURCES SUBJECT TO BACT ANALYSIS

HECA will consist of several facility blocks/systems representing sources of regulated air pollutants that are addressed in this BACT analysis. To evaluate possible emission control technologies, it is first important to understand the unique IGCC process and the supporting ancillary plant processes. The process descriptions for the various processes that make up HECA are included in Chapter 2 of this Application. The proposed BACT controls and associated emission rates for each emission unit are summarized in Table 3-1.

HECA includes one type of source unique to power generation facilities operating at this time – the CTG/HRSG equipped to combust syngas. It is important to emphasize that BACT for this source is based on the "best of class" in current diffusion combustor based syngas fired gas turbine technology. The emissions profile contained in this application for this source is as good as or better than other syngas IGCC permitted to date, as discussed later in this section. However, the IGCC BACT level emissions should not be compared to the natural gas combined cycle (NGCC) gas turbine technology using dry low NOx burner technology emission levels.

**Table 3-1**
**Proposed BACT for Project**

| Pollutant | Technology | Emission Limit |
|---|---|---|
| **CTG/HRSG Combustion Turbine (excluding Start up / Shutdown conditions).** | | |
| $NO_x$ | Diluent Injection, Selective Catalytic Reduction | 4 ppm $NO_x$ @ 15 percent $O_2$ on hydrogen-rich fuel and natural gas fuel, 3-hour average |
| CO | Good Combustion Practice (GCP), CO Catalyst | 3 ppm CO @ 15 percent $O_2$ on hydrogen-rich fuel, 5 ppm CO @ 15 percent $O_2$ on natural gas fuel |
| $PM/PM_{10}$ | GCP, Gas Cleanup, Gaseous Fuels | 24 lb/hr on hydrogen-rich fuel, 18 lb/hr on natural gas fuel |
| $SO_2$ | Hydrogen-rich Gas cleanup, pipeline quality natural gas | ≤ 5 ppmv in undiluted total sulfur (hydrogen-rich fuel) ≤ 0.75 grain / 100 SCF (12.65 ppm for natural gas) |
| VOC | CO Catalyst | 1 ppm VOC @ 15 percent $O_2$ on hydrogen-rich fuel, 2 ppm VOC @ 15 percent $O_2$ on natural gas fuel |
| $NH_3$ | Selective Catalytic Reduction | 5 ppm $NH_3$ slip on hydrogen-rich fuel and natural gas fuel |
| **Auxiliary CTG (excluding Start up / Shutdown conditions). Natural Gas fired. 103.3 MW** | | |
| $NO_x$ | Selective Catalytic Reduction | 2.5 ppm $NO_x$ @ 15 percent $O_2$ on natural gas fuel, 3-hour average |
| CO | CO Catalyst | 6.0 ppm CO @ 15 percent $O_2$ |
| $PM/PM_{10}$ | PUC regulated natural gas | 6 lb/hr on natural gas fuel |
| $SO_2$ | | ≤ 0.75 grain / 100 SCF (12.65 ppm for natural gas) |
| VOC | CO Catalyst | 2 ppm VOC @ 15 percent $O_2$ on natural gas fuel |

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

| Pollutant | Technology | Emission Limit |
|---|---|---|
| $NH_3$ | Selective Catalytic Reduction | 10 ppm $NH_3$ slip on natural gas fuel |
| **Cooling Towers** | | |
| $PM/PM_{10}$ | High Efficiency Drift Eliminators, Total Dissolved Solids (TDS) limit in circulating water, and Good Operating Practice | 0.0005 percent drift as percent of the circulating water |
| **Auxiliary Boiler, Natural Gas 142 MMBTU/hr** | | |
| $NO_x$ | Low $NO_x$ Combustor with FGR | 9 ppm $NO_x$ @ 3 percent $O_2$ on natural gas fuel |
| CO | GCP | 50 ppmvd @ 3 percent $O_2$ |
| $PM/PM_{10}$ | GCP, PUC grade natural gas fuel | 0.005 lb/MMBtu heat input |
| $SO_2$ | | ≤ 0.75 grain / 100 SCF (12.65 ppm for natural gas) |
| VOC | | 0.004 lb/MMBtu heat input |
| **Emergency Diesel Engines (2 Emergency Generators )** | | |
| $NO_x$ | Combustion controls, restricted operating hours | 0.5 g/brake horsepower (Bhp)/hr |
| CO | | 0.29 g/Bhp-hr |
| $PM/PM_{10}$ | Combustion controls, Low Sulfur Diesel fuel, restricted operating hours | 0.03 g/Bhp-hr |
| $SO_2$ | | N/A |
| VOC | | 0.11 g/bhp-hr |
| **Emergency Diesel Engines (Fire Pump)** | | |
| $NO_x$ | Combustion controls, restricted operating hours | 1.5 g/bhp-hr |
| CO | | 2.60 g/bhp-hr |
| $PM/PM_{10}$ | Combustion controls, Low Sulfur Diesel fuel, restricted operating hours | 0.015 g/bhp-hr |
| $SO_2$ | | N/A |
| VOC | | 0.14 g/bhp-hr |
| **Gasification Flare (an elevated flare)** | | |
| $NO_x$, CO, $PM/PM_{10}$, $SO_2$, VOC | GCP, gaseous fuel only, Gas cleanup/Limit on reduced sulfur in hydrogen-rich fuel | |
| **Thermal Oxidizer (Sulfur Recovery System)** | | |
| $NO_x$ | GCP | 4.8 lb/hr 24-hour average |
| CO | | 4.0 lb/hr, 1-hour average |
| $PM/PM_{10}$ | | 0.16 lb/hr 24-hour average |
| $SO_2$ | GCP, Gas cleanup | 2.02 lb/hr, 3-hour average |
| VOC | GCP | 32.84 lb/hr, annual average |

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

| Pollutant | Technology | Emission Limit |
|---|---|---|
| **SRU Flare (an elevated flare with natural gas assist)** | | |
| $NO_x$ | GCP | |
| CO | GCP | |
| $PM/PM_{10}$ | GCP, gaseous fuel only | |
| $SO_2$ | GCP, Caustic Scrubber | |
| VOC | GCP | |
| **$CO_2$ Vent** | | |
| CO | Gas Cleanup | 1000 ppmv |
| $H_2S$ | Acid Gas Removal | 10 ppmv |
| VOC | Gas Cleanup | 40 ppmv |
| **Gasifier Warming (refractory heater)** | | |
| $NO_x$ | GCP | 0.11 lb/MMBtu, higher heating value (HHV) |
| CO | GCP | 0.09 lb/MMBtu, HHV |
| $PM/PM_{10}$ | GCP, gaseous fuel only | 0.008 lb/MMBtu, HHV |
| $SO_2$ | GCP, PUC grade Natural gas | 0.002 lb/MMBtu, HHV (12.65 ppm) |
| VOC | GCP | 0.007 lb/MMBtu, HHV |
| **Feedstock** | | |
| $PM/PM_{10}$ | Dust Collector | 0.005 grain/scf outlet dust loading |

Source: HECA Project

Notes:
BACT = best available control technology
CO = carbon monoxide
CPUC = California Public Utility Commission
CTG = combustion turbine generator
FGR = flue gas recirculation
MMBTU = million British thermal units
$NO_x$ = nitrogen dioxide
$NH_3$ = ammonia
$O_2$ = oxygen
$PM/PM_{10}$ = particulate matter/particulate matter less than 10 microns
ppm = parts per million
ppmvd = parts per million volumetric dry
SCF = standard cubic feet
$SO_2$ = sulfur dioxide
VOC = volatile organic compound
HHV = higher heating value

## 4.0 CONSIDERATION OF ALTERNATIVE GENERATING TECHNOLOGY

This section addresses recent guidance relating to the need for consideration of alternative electrical generating technologies for the proposed project, as part of the BACT analysis. Compared to pulverized coalpc (PC)-fired boilers and circulating fluidized bed (CFB) boilers, the proposed IGCC process is the very lowest emitting solid fuel-based electricity generating technology available, and selection of a completely different solid fuel-based generating technology would not result in lower emissions. Later portions of this BACT analysis address the specific controls that are proposed to minimize the emissions from the proposed IGCC process.

The first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions of the source and pollutant under evaluation. The most common control technologies considered in a BACT analysis are add-on control measures and inherent process characteristics that minimize generation of pollutants, in addition to process or work practice modifications to improve the emissions performance of a proposed project. These types of process modifications/measures, when applicable, are properly considered in a BACT analysis.

In contrast, consideration of alternatives that would involve completely "redefining the design" of the proposed process are not required to be considered (1990 Draft New Source Review Workshop Manual, Section IV.A.3). Alternative generating processes, such as natural-gas–fired combined-cycle plants, represent a completely different family of power generation plant designs from IGCC. Although there are certain types of components in common, such as cooling towers and steam-driven turbine generators, the technical basis for a gas-fired plant differs markedly from that of an IGCC facility.

Because CFB or PC boilers or a natural-gas–fired electrical generating plant would be a completely different processes, and represent "redefining the design" compared to IGCC, it is reasonable to conclude that the USEPA would not require that the BACT analysis for HECA compare these different technologies. This point was recently reinforced in a December 13, 2005 letter from Stephen Page, Director of the USEPA's OAQPS, to E3 Consulting, LLC regarding BACT requirements for proposed coal-fired power plant projects. In that letter, the USEPA clarified that a BACT analysis need not consider an alternative "which would wholly replace the proposed facility with a different type of facility."

The remainder of this BACT analysis describes the various emission control options for specific IGCC facility processes, and demonstrates that as proposed, HECA would achieve the lowest emissions rate technically and economically feasible for such a facility.

## 5.0 OTHER PERMITTED IGCC PROJECTS

For this BACT analysis, the available control options were identified by querying the RBLC database and by consulting available literature on control options for IGCC. Applications and/or permits from a number of other IGCC facilities that have completed the New Source Review process were also reviewed to provide additional reference material for this BACT analysis. A brief summary of the other recently permitted IGCC plants in the United States and their emissions limits is presented in this section.

Other recently permitted IGCC facilities that will be used as comparison reference for this BACT analysis are:

- Duke Energy, Edwardsport Generating Station
- ERORA Group, Taylorville Energy Center
- ERORA Group, Cash Creek Generating Station

The air permits, BACT analyses, and additional literature were reviewed for each of these recently permitted IGCC facilities. Each facility is discussed briefly below. The facilities that were subject to BACT determinations are listed as such.

**Duke Energy, Edwardsport Generating Station:** Duke Energy Indiana, owner of Edwardsport Generating Station, obtained approval, via Indiana Department of Environmental Management Significant Modification Title V Permit, to install an IGCC facility in Knox County, Indiana. The Title V Significant Modification Permit was issued in January 2008. The 630–megawatt (net) IGCC plant will replace four older, less efficient generating units capable of generating approximately 160 megawatts at the Edwardsport site. The Edwardsport Generating Station is expected to use coal as feedstock, and SCR as add-on control to minimize $NO_x$ emissions from the plant.

***ERORA Group - Taylorville Energy Center:*** The ERORA Group is developing the Taylorville Energy Center, a 630 megawatt (net) IGCC facility to be located in Christian County, southern Illinois. Taylorville Energy Center obtained a final Illinois Environmental Protection Agency air permit in June 2007. Taylorville Energy Center proposed to use GE Energy gasification technology and local coals (Illinois coal) as the feedstock. Taylorville Energy Center will use Selexol® AGR systems, as well as SCR. The Taylorville Energy Center site is in an ozone attainment area, so SCR is not required for BACT purposes. ERORA is using SCR to minimize $NO_x$ emissions from the plant, but not as BACT. This will allow them to minimize the cost to acquire $NO_x$ allowances from the market. ERORA notes that in order to increase the chance that the SCR system will work in this unproven application on coal-derived syngas, higher sulfur removal, by using Selexol® instead of MDEA, will be required.

***ERORA Group – Cash Creek Generating Station****:* The ERORA Group is developing the Cash Creek Generation Station IGCC facility, to be located near Owensboro, Henderson County, Kentucky. Cash Creek Generation Station obtained a final Kentucky DAQ air permit in January 2008. The 630 megawatt IGCC proposes to use GE Energy gasification technology and local coals (Kentucky coal) as the feedstock. Cash Creek Generation Station will use Selexol® AGR systems, as well as SCR. Because the proposed facility site is in an ozone attainment area, SCR is not required for BACT purposes. ERORA is using SCR to minimize $NO_x$ emissions from the plant, but not as BACT. This will allow them to minimize the cost to acquire $NO_x$ allowances from the market. ERORA notes that in order to increase the chance that the SCR system will work in this unproven application on coal-derived syngas, higher sulfur removal, by using Selexol® instead of MDEA, will be required.

## 6.0 SOURCE-SPECIFIC BACT ANALYSIS

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants that would be emitted from the proposed Project to determine appropriate BACT emission limits. This BACT analysis is based on the current state of IGCC technology, energy and environmental factors, current expected economics, energy, and technical feasibility.

## 6.1 CTG/HRSG BACT Analysis

The following is the BACT analysis for the proposed combustion turbine. The proposed combustion turbine will be a GE 7FB model turbine with a nominal capacity of 232 megawatt. The GE 7FB is a new turbine model designed to optimally uses hydrogen-rich fuel and natural gas, and includes changes to the fuel system, combustion system, and hot gas path. The use of hydrogen-rich fuel requires the use of a diffusion-type combustor, because the high concentration of hydrogen precludes the use of dry low $NO_x$ (DLN) combustor technology.

The air permits, BACT analyses, and additional literature for each of the recently permitted IGCC facilities discussed in the last section were reviewed. Table 6-1 summarizes the criteria pollutant emission levels permitted for the combustion turbine units at each facility.

### 6.1.1 Nitrogen Oxides BACT Analysis for the CTG/HRSG

The criteria pollutant $NO_x$ is primarily formed in combustion processes via the reaction of elemental nitrogen and oxygen in the combustion air (thermal $NO_x$), and the oxidation of nitrogen contained in the fuel (fuel $NO_x$). The hydrogen-rich fuel produced in the proposed project contains negligible amounts of fuel-bound nitrogen; therefore, it is expected that essentially all $NO_x$ emissions from the CTG/HRSG will originate as thermal $NO_x$.

The rate of formation of thermal $NO_x$ in a combustion turbine is a function of residence time, oxygen radicals, and peak flame temperature. Front-end $NO_x$ control techniques are aimed at controlling one or more of these variables during combustion. Examples include dry low-$NO_x$ combustors, flue gas recirculation, and diluent injection (steam, water, or nitrogen). These technologies are considered to be commercially available pollution prevention techniques. It is necessary to recognize the fundamental differences between natural-gas-fired and hydrogen-rich fuel-fired combustion turbines in evaluating these techniques. Compared to natural gas and syngas, hydrogen-rich fuel has a much higher hydrogen content (natural gas is often over 90 percent methane), and a much lower heating value (about 250 Btu/scf for hydrogen-rich fuel vs. 1,000 Btu/scf for natural gas). HECA will be fired on hydrogen-rich fuel. The other power plants used for comparison in this Appendix are fired on syngas.

#### *1. Identify Control Technologies*

The following $NO_x$ control technologies were evaluated for the proposed CTG/HRSG:

*Combustion Process Controls*

- Dry Low $NO_x$ Burner
- Diluent Injection

*Post-Combustion Controls*

- $SCONO_x$™
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

**Table 6-1**
**Permitted Criteria Pollutant BACT Limits for Combined-Cycle Combustion Turbine**

| Facility | HECA | Cash Creek Generation Station | Edwardsport Generating Station | Taylorville Energy Center |
|---|---|---|---|---|
| Location | Kern County, CA | Henderson County, KY | Knox County, IN | Christian County, IL |
| MW | 250 | 630 | 630 | 630 (net) |
| Turbine | GE 7FB | GE 7FB | GE 7FB | GE 7FB |
| $NO_x$ | 4 ppmc on hydrogen-rich fuel (0.019 lb/MMBtu), 4.0 ppmc on Natural Gas (0.016 lb/MMBtu) | 0.0331 lb/MMBtu (approx 5 ppmc) Syngas 0.0246 lb/MMBtu on Nat Gas | 0.027 lb/MMBtu Syngas 0.018 lb/MMBtu on Nat Gas | 0.034 lb/MMBtu (5.0 ppmc) Syngas 0.025 lb/MMBtu on Nat Gas |
| $SO_2$ | ≤ 5 ppmv in undiluted hydrogen-rich fuel ((0.003 lb/MMBtu) 0.75 grains/100 scf of total sulfur on Nat Gas (0.002 lb/MMBtu) | 0.0158 lb/MMBtu (3.8 ppmc) Syngas 0.0006 lb/MMBtu on Nat Gas | 0.0138 lb/MMBtu Syngas 0.0006 lb/MMBtu on Nat Gas | 0.016 lb/MMBtu Syngas (10 ppm Sulfur in Syngas) 0.001 lb/MMBtu on Nat Gas. |
| CO | 3 ppmc on Hydrogen-rich fuel (0.008 lb/MMBtu), 5 ppmc on Nat Gas (0.012 lb/MMBtu) | 0.0485 lb/MMBtu Syngas 0.0449 lb/MMBtu on Nat Gas | 0.0441 lb/MMBtu Syngas 0.0421 lb/MMBtu on Natural Gas | 0.049 lb/MMBtu (25.0 ppmvd) Syngas 0.045 lb/MMBtu (25.0 ppmvd) on Nat Gas |
| $PM_{10}$ (Scaled to HECA MW size) | 24 lb/hr on hydrogen-rich fuel and 18 lb/hr on Nat Gas | 47 lb/hr on syngas and 35 lb/hr on Nat Gas | 39.1 lb/hr on syngas and 18.1 lb/hr on Nat Gas | 48 lb/hr on syngas and 24 lb/hr on Nat Gas |
| VOC | 1 ppmc on Hydrogen-rich fuel (0.0016 lb/MMBtu), 2 ppmc on Nat Gas (0.0028 lb/MMBtu) | | 0.0016 lb/MMBtu Syngas or on Nat Gas | |

Notes:
Only HECA would use duct firing. All emissions specified for HECA apply to non–duct-firing and duct-firing operation.
HECA $SO_2$ on natural gas is worst case short-term average based on limit of 0.75 gr./100 scf.
Taylorville CO values inconsistent in ratio of lb/MMBtu per ppmc for $NO_x$. Scaling ratio from $NO_x$ would result in CO value of 0.049 lb/MMBtu (11.8 ppmc.) on Hydrogen-rich fuel(lower CO ppmc would be more conservative).

CO = carbon monoxide
MMBtu = million British thermal units
MW = megawatt
$NO_x$ = oxides of nitrogen
$PM_{10}$ = particulate matter 10 microns or less in diameter

**Table 6-1**
**Permitted Criteria Pollutant BACT Limits for Combined-Cycle Combustion Turbine**

| Facility | HECA | Cash Creek Generation Station | Edwardsport Generating Station | Taylorville Energy Center |
|---|---|---|---|---|

ppm = parts per million
ppmc = parts per million by volume, dry basis, corrected to 15 percent O2
$SO_2$ = sulfur dioxide
VOC = volatile organic compound

## 2. Evaluate Technical Feasibilities

- Dry Low-$NO_x$ Combustor

DLN combustor technology has been successfully demonstrated to reduce thermal $NO_x$ formation from natural-gas combustion turbines. This is done by designing the combustors to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual combustor's flame envelope. Combustor design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed combustor design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher $NO_x$ emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal $NO_x$ formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Hydrogen-rich fuel is different than syngas and has a similar heating value, but with much less CO and carbon dioxide. Hydrogen-rich fuel differs from natural gas in heating value, gas composition, and flammability characteristics. Available DLN combustor technologies are designed for natural gas (methane-based) fuels and will not operate on the syngas (hydrogen/CO-based) fuels used by an IGCC combustion turbine. DLN combustors are not technically feasible for this application due to the potential for explosion hazard in the combustion section due primarily to the high hydrogen content of the syngas. No manufacturer currently makes DLN combustors that can be used for a combustion turbine fueled by petroleum coke (petcoke) or coal-derived syngas. Research is ongoing to develop DLN for syngas-fueled combustion turbines; however, such combustors are not yet commercially available. Thus, DLN combustor is not a technically feasible control option for this unit.

- Diluent Injection

Higher peak flame temperature during combustion may increase thermodynamic efficiency, but it also increases the formation of thermal $NO_x$. The injection of an inert diluent such as atomized water, steam, or nitrogen into the high-temperature region of a combustor flame serves to inhibit thermal $NO_x$ formation by reducing the peak flame temperature.

For the Project's CTG/HRSG, nitrogen is used as a diluent that reduces thermal $NO_x$ produced when hydrogen-rich gas is combusted. Steam is used as a diluent when natural gas is combusted. This method effectively lowers the fuel heat content, and consequently, the combustion temperature, thereby reducing $NO_x$ emissions.

GE guarantees that diluent injection can achieve turbine exhaust emission levels of 15 ppmvd $NO_x$ (at 15 percent oxygen) over a 3-hour average (excluding start up, shutdown, and upset periods) when firing 100 percent hydrogen-rich fuel. For natural-gas combustion and co-firing, GE guarantees emission levels of 25 ppmvd $NO_x$ (at 15 percent oxygen) from the turbine exhaust. The higher emission is caused by the difference in combustion characteristic of natural gas compared to the hydrogen-rich fuel.

A secondary benefit of diluent injection is that it will increase the mass flow of the exhaust. Therefore, the power output per unit of fuel input also increases.

Diluent injection represents an inherently lower-emitting process for IGCC units, and is a technically feasible control technology. Diluent injection (steam for natural gas and nitrogen for hydrogen-rich fuel) is proposed as the baseline case for the CGT/HRSG combustion turbine $NO_x$ BACT analysis. This $NO_x$ control technology and emission level have also been determined as BACT for all other recent IGCC permits, and has been demonstrated to achieve $NO_x$ emission rates of 15 ppmvd (at 15 percent $O_2$) when firing 100 percent syngas fuel. This $NO_x$ diluent injection control technology has been commercially demonstrated on syngas on the GE 7FA, but not on hydrogen-rich fuel on the GE 7FB.

- $SCONO_x$ ™

The $SCONO_x$ ™ system is an add-on control device that reduces emissions of multiple pollutants. $SCONO_x$™ uses a single catalyst for the reduction of CO, VOC, and $NO_x$, which are converted to $CO_2$, water ($H_2O$), and nitrogen ($N_2$).

All installations of the technology have been on small natural gas facilities, and have experienced performance issues. The fact that $SCONO_x$™ has not been applied to large-scale natural gas combustion turbines creates concerns regarding the timing, feasibility, and cost-effectiveness of necessary design improvements. $SCONO_x$™ has also not been applied to syngas (or hydrogen-rich fuel).

In evaluating technical feasibility for large IGCC projects, the additional concerns are:

– $SCONO_x$™ uses a series of dampers to re-route air streams to regenerate the catalyst. The proposed HECA project is significantly larger than the facilities where $SCONO_x$™ has been used. This would require a significant redesign of the damper system, which raises feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the HECA CTG/HRSG.

– $SCONO_x$™ would not be expected to achieve lower guaranteed $NO_x$ levels than SCR, and, for reasons described above, it has even greater feasibility concerns with respect to application on IGCC turbines than those for SCR.

For the above reasons, $SCONO_x$™ is considered technically infeasible for this unit.

- Selective Non-Catalytic Reduction

Selective non-catalytic reduction is a post-combustion $NO_x$ control technology in which a reagent ($NH_3$ or urea) is injected into the exhaust gases to react chemically with $NO_x$ to form elemental nitrogen and water without the use of a catalyst. The success of this process in reducing $NO_x$ emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas, which must occur within a narrow flue gas temperature zone (typically from 1,700 to 2,000 degrees Fahrenheit [°F]).

The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to $NO_x$. Below the lower end of the temperature range, the reagent will not react with the $NO_x$ resulting in very high $NH_3$ slip concentrations ($NH_3$ discharge from the stack).

This technology is occasionally used in conventional fired heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been applied in IGCC service, primarily because there are no flue gas locations within the combustion turbine or upstream of the HRSG with the optimal requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Therefore, SNCR is not technically feasible for this unit.

- Selective Catalytic Reduction

SCR is a technology that achieves post-combustion reduction of $NO_x$ from flue gas within a catalytic reactor. The SCR process involves the injection of $NH_3$ into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of $NO_x$ to molecular nitrogen. SCR is a common control technology for use on natural-gas–fired combustion turbines.

In the SCR process, $NH_3$, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the $NH_3$ reacts with $NO_x$ to form molecular nitrogen and water. The basic reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

The Project selected SCR and diluent injection technology to control $NO_x$ emissions from the CTG/HRSG unit. The SCR system reduces nitrogen oxide emissions from the HRSG stack gases by up to about 80 percent. Diluted 19 percent aqueous ammonia is injected into the stack gases upstream of a catalytic system that converts nitrogen oxide and ammonia to nitrogen and water.

It is anticipated that this combination of control processes will achieve a $NO_x$ emission limit of 4 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, when firing hydrogen-rich fuel, natural gas, or a combination of hydrogen-rich fuel and natural gas. This emission limitation represents a removal efficiency that is better than the approved emissions for recently permitted IGCC units. HRSG vendors confirm the feasibility of achieving the $NO_x$ levels cited in the revised AFC.

### 3. Rank Control Technologies

Among the control technologies considered in the previous subsection, only one was determined to be both technically feasible and commercially demonstrated at a cost level acceptable as a BACT option. Specifically, the feasible option is diluent injection upstream of the combustion zone to achieve a controlled level of 15 ppmvd $NO_x$ at 15 percent $O_2$ while firing hydrogen-rich fuel, and 25 ppmvd $NO_x$ at 15 percent $O_2$ while firing natural gas or a combination of hydrogen-rich fuel and natural gas.

Although there is no commercial demonstration of SCR performance for an IGCC plant using coal or petcoke feedstock, SCR technology has been proposed as emission limits for recently permitted IGCC projects. HRSG vendors confirm that SCR catalyst will be able to achieve combined $NO_x$ reduction down to 4 ppmvd at 15 percent oxygen, based on a 3-hour rolling average, on all firing scenarios.

### 4. Evaluate Control Options

The next step in a BACT analysis is to evaluate the feasible control technology. Based on the evaluation in the previous step, the only feasible technologies suitable for establishment of BACT limits are diluent injection and SCR. The principal environmental consideration with respect to implementation of SCR is that, while it will reduce $NO_x$ emissions, it will add $NH_3$ emissions associated with use of $NH_3$ as the reagent chemical. A portion of the unreacted $NH_3$ passes through the catalyst and is emitted from the stack. This is called ammonia slip, and the magnitude of these emissions depends on the catalyst activity and the degree of $NO_x$ control desired. For this project, the concentration of ammonia slip is limited to 5 ppmvd at 15 percent oxygen.

Table 6-2 shows the typical $NO_x$ BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed $NO_x$ BACT for the CTG/HRSG.

As shown in Table 6-2, the BACT limitation for $NO_x$ emissions from HECA CTG/HRSG is more stringent than the historic BACT determination for other recently permitted IGCC projects.

NSPS 40 CFR 60 Subpart Da is considered as the BACT "floor" for this source category. As shown above, the BACT emission limit proposed for HECA is significantly lower than the applicable NSPS Subpart Da limit of 0.5 lb/MMBTU heat input for gaseous fuel. The proposed $NO_x$ reduction technology is also more stringent than the NSPS Subparts Da recommended minimum reduction efficiency of 25 percent.

### *5. Select Control Technology*

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, for this application of hydrogen-rich fuel-fired combustion turbines within an IGCC facility, diluent injection in the combustion turbine and SCR installation as post-combustion $NO_x$ control are the appropriate control techniques for setting BACT-based emission limits. The BACT selection described above is strongly supported by recent precedents for similar IGCC projects.

The proposed BACT limits based on this technology are 4 ppmvd $NO_x$ at 15 percent $O_2$ for hydrogen-rich–fuel firing, natural-gas firing, and co-firing.

**Table 6-2**
**$NO_x$ BACT Emission Limit Comparison**

| Facility | State | MW | Turbine | $NO_x$ BACT Technology | Emission Limit on Hydrogen-Rich or Syngas Fuels | | Emission Limit on Natural Gas | |
|---|---|---|---|---|---|---|---|---|
| | | | | | ppm | lb/MMBTU Hydrogen-Rich Fuel | ppm | lb/MMBTU NG |
| HECA | CA | 250 | GE Model Number 7FB. | SCR | 4[a] | 0.019 | 4[a] | 0.016 |
| Cash Creek Generation Station | KY | 630 | GE Model Number 7FB. | SCR | 5[a] | 0.0331 | | 0.0246 |
| Edwardsport Generating Station | IN | 630 | GE Model Number 7FB. | SCR operated in trial mode | | 0.027[b] | | 0.018[b] |
| Taylorville Energy Center | IL | 630 (net) | GE Model Number 7FB. | SCR | 5[a] | 0.034 | | 0.025 |

Notes:
[a] Parts per million by volume, dry basis, corrected to 15 percent $O_2$.
[b] Calculated from mass emissions rate of 57 lb/hr on hydrogen-rich fuel and 38 lb/hr on natural gas.
MMBtu = million British thermal units
MW = megawatt
ppm = parts per million
SCR = selective catalytic reduction

### 6.1.2 Carbon Monoxide BACT Analysis for the CTG/HRSG

CO is a product of incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. However, these same control factors can increase $NO_x$ emissions. Conversely, lower $NO_x$ emission rates achieved through flame temperature control (by diluent injection) can increase CO emissions for natural gas and un-shifted syngas. Thus, a compromise must be established whereby the flame temperature reduction is set to achieve the lowest $NO_x$ emission rate possible while keeping CO emissions to an acceptable level. However, CO emissions are inherently low for hydrogen-rich fuels that contain very little reduced carbon and are less affected by the conventional trade-off between CO and $NO_x$.

### *1. Identify Control Technologies*

The following CO control technologies were evaluated for the proposed CTG/HRSG:

*Combustion Process Controls*

- Good Combustion Practices (GCPs)

*Post-Combustion Controls*

- $SCONO_x$™
- Oxidation Catalyst

### *2. Evaluate Technical Feasibilities*

*Good Combustion Practices*

Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure optimum complete combustion. GE guarantees the turbine exhaust can achieve CO emission levels of 5 ppmvd CO when firing hydrogen-rich fuel, and 25 ppmvd CO when operating on natural gas.

This technology has been determined to be BACT for CO emissions in other operational or recently permitted IGCC projects.

- $SCONO_x$™

  The $SCONO_x$ system was evaluated in the $NO_x$ BACT analysis, and determined to be not technically feasible for this unit.

- Oxidation Catalysts

  Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize CO into $CO_2$. Because of the catalyst fouling concerns, the use of oxidation catalysts has been previously limited to processes combusting natural gas. Oxidation catalysts have never been applied to coal-based IGCC processes. Other operational or recently permitted IGCC projects determined GCPs as the only feasible BACT for CO emissions. The project anticipated CO conversions up to 90 percent are attainable across the CO catalyst. HECA proposed CO emission limits of 3.0 ppmvd at 15 percent $O_2$ while firing hydrogen-rich fuel, and 5.0 ppmvd CO at 15 percent $O_2$ while firing natural gas.

### *3. Rank Control Technologies*

Oxidation catalyst is the only technically feasible CO control technology identified in addition to Good Combustion Practices.

### *4. Evaluate Control Options*

GCP is considered the baseline and only feasible and commercially demonstrated CO control technology for IGCC combustion turbines. GCP has been selected as BACT for all other recent IGCC permits. Oxidation catalysts have not been applied to the other coal-based IGCC processes. In comparison to other operational or recently permitted IGCC projects, this emission limitation represents a removal efficiency that is lower than the emission achieved in practice at currently operating IGCC units, and the lowest proposed emission limits for proposed coal-fired units, including other proposed IGCC units.

Table 6-3 shows the typical CO BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed CO BACT for the CTG/HRSG.

**Table 6-3**
**CO BACT Emission Limit Comparison**

| | | | | | Emission Limit on Hydrogen-Rich Fuel | | Emission Limit on Nat Gas | |
|---|---|---|---|---|---|---|---|---|
| **Facility** | **State** | **MW** | **Turbine** | **CO BACT Technology** | **ppm** | **lb/MMBTU Hydrogen-Rich Fuel or Syngas Fuels** | **ppm** | **lb/MMBTU NG** |
| HECA | CA | 250 | GE Model Number 7FB. | CO catalyst and GCP | 3[a] | 0.008 | 5[a] | 0.012 |
| Cash Creek Generation Station | KY | 630 | GE Model Number 7FB. | GCP | | 0.0485 | | 0.0449 |
| Edwardsport Generating Station | IN | 630 | GE Model Number 7FB. | GCP | | 0.0441b | | 0.0421b |
| Taylorville Energy Center | IL | 630 (net) | GE Model Number 7FB. | GCP | 25 | 0.049 | 25 | 0.045 |

Notes:
[a] Parts per million by volume, dry basis, corrected to 15 percent $O_2$.
[b] Calculated from mass emissions rate of 93 lb/hr on hydrogen-rich fuel and 88.7 lb/hr on natural gas.
MMBtu = million British thermal units
MW = megawatt
ppm = parts per million

As shown in Table 6-3, the BACT limitation for CO emissions from HECA CTG/HRSG is more stringent than the historic BACT determination for other recently permitted IGCC units. This emission limitation represents a removal efficiency that is better than the emission achieved in practice at currently operating IGCC units, and the lowest proposed emission limits compared to recently permitted IGCC units.

### *5. Select Control Technology*

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and oxidation catalyst are the appropriate control technique for setting BACT-based emission limits.

HECA proposed the CO BACT-based limit of 3.0 ppmvd at 15 percent $O_2$ while firing hydrogen-rich fuel, and 5.0 ppmvd CO at 15 percent $O_2$ while firing natural gas during non-startup operation, using GCPs and an oxidation catalyst.

## 6.1.3 Particulate Matter Emissions BACT Analysis for the CTG/HRSG

Particulate matter emissions from natural-gas — fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, ammonia compounds for the SCR reagent, dust drawn in from the ambient air that passes through the combustion turbine inlet air filters, and particles of carbon and hydrocarbons resulting from incomplete combustion. Low ash content and high combustion efficiency exhibit correspondingly low particulate matter emissions for other fuel such as hydrogen-rich fuel.

### *1. Identify Control Technologies*

The following particulate matter control technologies were evaluated for the proposed CTG/HRSG:

*Pre-Combustion Controls*

- Gas Cleanup (for hydrogen-rich fuel)

*Combustion Process Controls*

- Good Combustion Practices

*Post-Combustion Controls*

- Baghouse
- Electrostatic Precipitation

### *2. Evaluate Technical Feasibilities*

In a typical solid fuel combustion process, fuel particulate matter is removed by post-combustion processes such as fabric filters or electrostatic precipitators. However, in an IGCC plant, particulate matter could damage the turbine, so particulate matter is removed prior to combustion. Post-combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial combustion turbines burning gaseous fuels. Therefore, the use of ESPs and baghouses is considered technically infeasible control technology.

In the absence of add-on controls, the most effective control method demonstrated for gas-fired combustion turbines is the use of low-ash fuel, such as natural gas or hydrogen-rich fuel and GCPs. Therefore, it is necessary to use pre-combustion controls such as particulate removal as an integral part of the gasification process, in addition to GCPs.

The use of clean hydrogen-rich fuel and good combustion control is proposed as BACT for PM/ $PM_{10}$ control in the proposed HECA CTG/HRSG. These operational controls will limit filterable plus condensable PM/ $PM_{10}$ emissions to 24 lb/hr when operating on hydrogen-rich fuel, and 18 lb/hr when operating on natural gas.

### *3. Rank Control Technologies*

The use of clean fuels with low potential particulate emissions from optimum gas cleanup processes and GCPs were identified as the only technically feasible particulate emissions control technologies applicable to the proposed combustion turbines.

### *4. Evaluate Control Options*

The USEPA has indicated that particulate matter control devices are not typically installed on combustion turbines and that the cost of installing a particulate matter control device is prohibitive. When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the USEPA acknowledged, “Particulate emissions from stationary gas turbines are minimal.” Similarly, the recently revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for particulate matter control of stationary gas turbines have not been proposed or promulgated at a federal level.

Table 6-4 shows the typical PM BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA’s proposed PM BACT for the CTG/HRSG.

Based on the evaluation in the previous step, GCPs and optimum gas cleanup are considered as technically feasible PM/ $PM_{10}$ control technologies that are suitable for establishment of BACT limits. As shown in Table 6-4, HECA emission limitation represents a removal efficiency that is cleaner in comparison to other operational or recently permitted IGCC units. Therefore, the BACT limitation for PM emissions from HECA CTG/HRSG is more stringent than the historic BACT determination for other recently permitted IGCC units.

NSPS 40 CFR 60 Subpart Da is considered as the BACT “floor” for this source category. The BACT emission limits proposed in Table 6-4 are equivalent to 0.011 lb/MMBTU on hydrogen-rich fuel, and 0.008 lb/MMBTU on natural gas. These emission limits are significantly lower than the applicable NSPS Subpart Da limit of 0.03 lb/MMBtu heat input derived from the combustion of solid, liquid, or gaseous fuel.

### 5. Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and optimum gas cleanup are the appropriate control technique for setting BACT-based emission limits. The use of optimum gas cleanup to produce clean fuels with low potential particulate emissions and GCPs were selected as LAER for particulate emissions from the proposed combustion turbines. The following emission limit resulting from the implementation of these technologies is proposed for each combustion turbine.

HECA proposed the PM BACT-based limit of 24 lb/hr while firing hydrogen-rich fuel, and 18 lb/hr while firing natural gas during non-startup operation, using GCPs and optimum gas cleanup.

**Table 6-4**
**PM BACT Emission Limit Comparison**

| Facility | State | MW | Turbine | PM10 BACT Technology | Emission Limit on Hydrogen-Rich Fuel or Syngas Fuels | Emission Limit on Natural Gas |
|---|---|---|---|---|---|---|
| | | | | | lb/hr | lb/hr |
| HECA | CA | 250 | GE Model Number 7FB. | Gas Cleanup and GCP | 24 | 18 |
| Cash Creek Generation Station | KY | 630 | GE Model Number 7FB. | Gas Cleanup and GCP | 47 | 35 |
| Edwardsport Generating Station | IN | 630 | GE Model Number 7FB. | Gas Cleanup and GCP | 39.1 | 18.1 |
| Taylorville Energy Center | IL | 630 (net) | GE Model Number 7FB. | Gas Cleanup and GCP | 48 | 24 |

Notes:
MW = megawatt
$PM_{10}$ = particulate matter 10 microns in diameter

### 6.1.4 Sulfur Dioxide and Sulfuric Acid Mist BACT Analysis for the CTG/HRSG

Sulfur dioxide emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel usage. The combustion of hydrogen-rich fuel in the combustion turbines creates primarily $SO_2$ and small amounts of sulfite ($SO_3$) by the oxidation of the fuel sulfur. The $SO_3$ can react with the moisture in the exhaust to form sulfuric acid mist, or $H_2SO_4$. Emissions of these sulfur species can be controlled, either by limiting the sulfur content of the fuel (pre-combustion control), or by scrubbing the $SO_2$ from the exhaust gas (post-combustion control).

## *1. Identify Control Technologies*

The following sulfur dioxide and sulfuric acid mist control technologies were evaluated for the proposed CTG/HRSG when operating on hydrogen-rich fuel:

*Pre-Combustion Controls*

- Chemical Absorption Acid Gas Removal (AGR), e.g., methyldiethanol-amine (MDEA)
- Physical Absorption Acid Gas Removal, e.g., Selexol®, Rectisol

*Post-Combustion Controls*

- Flue Gas Desulfurization

The sulfurs dioxide BACT for the proposed CTG/HRSG when operating on natural gas is PUC-grade natural gas fuel with less than 0.75 grain/100 scf sulfur content.

## *2. Evaluate Technical Feasibilities*

- Acid Gas Removal

  In the gasification process, sulfur in the petcoke or coal feedstock converts primarily to hydrogen sulfide ($H_2S$). Solvent-based acid gas cleanup is commonly used for "gas sweetening" processes in petroleum refinery fuel gas or tail gas treating units, where $H_2S$ in the process gas is removed before use as a fuel. The removed $H_2S$ is recovered either as elemental sulfur in a Sulfur Recovery Unit (e.g., using a Claus process).

  In a chemical absorption process, acid gases in the sour syngas are removed by chemical reactions with a solvent that is subsequently separated from the gas and regenerated. The chemical absorption occurs in amine-based systems that use solvents such as MDEA. Amine solvents chemically bond with the $H_2S$. The $H_2S$ can be easily liberated with low-level heat in a stripper to regenerate the solvent. However, amine-based systems such as MDEA are not effective at removing COS and have not demonstrated the deep total sulfur removal levels required by the Project.

  Lower levels of sulfur removal are possible using physical absorption AGR systems. Physical absorption methods, including Selexol® and Rectisol, use solvents that dissolve acid gases under pressure. Selexol® or Rectisol are normally applied when low syngas sulfur levels are required for SCR. Solubility of an acid gas is proportional to its partial pressure and is independent of the concentrations of other dissolved gases in the solvent. Consequently, increased operating pressure in an absorption column facilitates separation and removal of an acid gas like $H_2S$. The dissolved acid gas can then be removed from the solvent, which is regenerated by depressurization in a stripper.

  To selectively remove $H_2S$ and $CO_2$, two absorption and regeneration columns or two-stage process are required. In general, $H_2S$ is selectively removed in the first column by a lean solvent that has been deeply stripped with steam, while $CO_2$ is removed from the now $H_2S$-free gas in the second absorber. The second-stage solvent can be regenerated if very deep $CO_2$ removal is required. If only bulk $CO_2$ removal is required, then the flashed gas containing the bulk of the CO, can be vented, and the second regenerator duty can be substantially lowered or totally eliminated.

A detailed technology assessment was completed by the Applicant and discussed in Section 6, Alternatives.

- Flue Gas Desulfurization

  Flue gas desulfurization is a post-combustion $SO_2$ control technology that reacts an alkaline with $SO_2$ in the exhaust gas. Typical FGD processes operate by contacting the exhaust gas downstream of the combustion zone with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic $SO_2$. FGD technologies may be wet, semi-dry, or dry, based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes that use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD systems in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack

  FGD systems are commonly employed in conventional PC plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95 percent sulfur removal. However, FGD cannot provide as high a level of control as the pre-combustion AGR systems. In addition, FGD has the environmental drawbacks of substantial water usage and the need to dispose of a solid byproduct (the scrubber sludge). The solid by-product requires the installation of a significant number of ancillary support systems to accommodate treatment, handling, and disposal. Given these disadvantages and the fact that FGD could not achieve the high removal efficiencies associated with AGR, even though FGD is not technically infeasible, it is not considered to be a reasonable technical option for IGCC. Therefore FGD will not be considered further in this BACT analysis

### *3. Rank Control Technologies*

Both chemical and physical absorption methods for AGR are considered feasible for an IGCC, and can achieve control of the sulfur in syngas up to 99 percent or better. Both of these systems are further considered in the BACT analysis. A detailed technology assessment was completed by the Applicant and discussed in Section 6, Alternatives.

### *4. Evaluate Control Options*

Physical absorption AGR systems (including Selexol® and Rectisol) are considered as feasible sulfur dioxide and sulfuric acid mist control technology for the proposed CTG/HRSG turbine. Selexol® has been selected as BACT for all other recent IGCC permits. Rectisol has not yet been applied to other coal-based IGCC processes but has been widely used in gasification projects in the chemical industry where both deep sulfur removal and $CO_2$ removal are required. Both Rectisol and Selexol® are considered viable alternatives or MDEA. However, the Project selected Rectisol because there are more units operating at similar capacities and similar conditions to those required for the Project, making Rectisol the more proven alternative.

Table 6-5 shows the typical $SO_2$ BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed $SO_2$ BACT for the CTG/HRSG.

**Table 6-5**
**$SO_2$ BACT Emission Limit Comparison**

| Facility | State | MW | Turbine | $SO_2$ BACT Technology | Emission Limit on Hydrogen-Rich Fuel | | Emission Limit on Nat Gas | |
|---|---|---|---|---|---|---|---|---|
| | | | | | ppm | lb/MMBTU Hydrogen-Rich Fuel or Syngas Fuels | ppm | lb/MMBTU NG |
| HECA | CA | 250 | GE Model Number 7FB. | AGR, Rectisol | ≤ 5 ppm Sulfur in undiluted Hydrogen-rich fuel | 0.003 | 0.75 grains/ 100 scf | 0.002 |
| Cash Creek Generation Station | KY | 630 | GE Model Number 7FB. | AGR, Selexol® | 3.8a | 0.0158 | | 0.0006 |
| Edwardsport Generating Station | IN | 630 | GE Model Number 7FB. | AGR, Selexol® | | 0.0138b | | 0.0006b |
| Taylorville Energy Center | IL | 630 (net) | GE Model Number 7FB. | AGR, Selexol® | 10 ppm Sulfur in Hydrogen-rich fuel | 0.016 | | 0.001 |

Notes:
[a] Parts per million by volume, dry basis, corrected to 15 percent $O_2$.
[b] Calculated from mass emissions rate of 2.9 lb/hr on hydrogen-rich fuel and 1.30 lb/hr on natural gas.
MMBtu = million British thermal units
MW = megawatt
ppm = parts per million

As shown in Table 6-5, the BACT limitation for $SO_2$ emissions from HECA CTG/HRSG when firing hydrogen-rich fuel is more stringent than the historic BACT determination for other recently permitted IGCC units. This emission limitation represents a removal efficiency that is better than the emission achieved in practice at currently operating IGCC units, and the lowest proposed emission limits compared to recently permitted IGCC units.

NSPS 40 CFR 60 Subpart Da is considered as the BACT "floor" for this source category. The proposed $SO_2$ emission limits are significantly lower than the applicable NSPS Subpart Da limit of 180 nanograms per joule (1.4 lb/MWh) or 95 percent reduction on a 30-day rolling average.

When firing natural gas, sulfur dioxide emission from CTG/HRSG is slightly higher than other recently permitted IGCC units. The sulfurs dioxide BACT for the proposed CTG/HRSG when operating on natural gas is PUC-grade natural gas fuel with less than 0.75 grain/100 scf sulfur content.

#### *5. Select Control Technology*

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. HECA selected Rectisol as syngas cleanup control technology to remove sulfur dioxide from the hydrogen-rich fuel stream entering the CTG/HRSG. The reduction efficiency of Rectisol is above the NSPS floor requirement, and the overall performance of this technology is more stringent than the historic BACT determination for other recently permitted IGCC units. The following emission limit resulting from the implementation of these technologies is proposed for each combustion turbine.

HECA proposed the PM BACT-based limit of ≤ 5 ppmv sulfur in undiluted $H_2$-rich syngas, and ≤0.75 grains/100 scf of natural gas sulfur content, using an AGR system (Rectisol) and PUC-grade natural gas.

### 6.1.5 Volatile Organic Compounds BACT Analysis for the CTG/HRSG

VOCs are a product of incomplete combustion of the organic components in the hydrogen-rich fuel. Hydrogen-rich fuel contains very low concentrations of VOC; therefore, emissions of VOC are inherently very low. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to ensure complete combustion. A survey of the RBLC database indicated that good combustion control and burning clean gas fuel are the VOC control technologies primarily determined to be BACT. The advantage of IGCC technology is the fact that the combustion turbine operates on hydrogen-rich fuel, which contains a very low organic content, and yields very low levels of uncombusted VOC emissions.

#### *1. Identify Control Technologies*

The following VOC control technologies were evaluated for the proposed CTG/HRSG:

*Combustion Process Controls*

- Good Combustion Practices

*Post-Combustion Controls*

- $SCONO_x$™
- Oxidation Catalyst

### 2. Evaluate Technical Feasibilities

- Good Combustion Practices

  GCPs include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure optimum complete combustion.

  This technology has been determined to be BACT for VOC emissions in other operational or recently permitted IGCC projects.

- $SCONO_x$™

  The $SCONO_x$ system was evaluated in the $NO_x$ BACT analysis, and determined to be not technically feasible for this unit.

- Oxidation Catalysts

  Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize VOC. The catalyst beds that functions to reduce CO emissions can also be effective in reducing VOC emissions. Such systems typically achieve a maximum VOC removal efficiency of up to 50 percent, while providing control for CO.

  Because of the catalyst fouling concerns, the use of oxidation catalysts has been previously limited to processes combusting natural gas. Oxidation catalysts have never been applied to coal-based IGCC processes. Other operational or recently permitted IGCC projects determined GCPs as the only feasible BACT for CO emissions. GE guarantees the turbine exhaust can achieve VOC emission levels of 1.0 ppmvd VOC (at 15 percent oxygen) when firing hydrogen-rich fuel, and 2.0 ppmvd CO (at 15 percent oxygen) when operating on natural gas.

### 3. Rank Control Technologies

Oxidation catalyst is the only technically feasible VOC control technology identified in addition to GCPs.

### 4. Evaluate Control Options

GCPs is considered the baseline and only feasible and commercially demonstrated VOC control technology for IGCC combustion turbines. GCP has been selected as BACT for all other recent IGCC permits. Oxidation catalysts have never been applied to other coal-based IGCC processes. In comparison to other operational or recently permitted IGCC projects, this emission limitation represents a removal efficiency that is lower than the emission achieved in practice at currently operating IGCC units, and the lowest proposed emission limits for proposed coal-fired units, including other proposed IGCC units.

Table 6-6 shows the typical VOC BACT determination (when firing hydrogen-rich fuel and natural gas, respectively) and control technology for other recently permitted IGCC projects, in comparison with HECA's proposed VOC BACT for the CTG/HRSG.

As shown in Table 6-6, the BACT limitation for VOC emissions from HECA CTG/HRSG is comparable to the historic BACT determination for other recently permitted IGCC units. This emission limitation represents a removal efficiency that is as good as the emissions proposed in recently permitted IGCC units

### *5. Select Control Technology*

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and oxidation catalyst are the appropriate control technique for setting BACT-based emission limits.

HECA proposed the VOC BACT-based limit of 1.0 ppmvd at 15 percent $O_2$ while firing hydrogen-rich fuel, and 2.0 ppmvd VOC at 15 percent $O_2$ while firing natural gas during non-startup operation, using GCPs and oxidation catalyst.

**Table 6-6**
**VOC BACT Emission Limit Comparison**

| Facility | State | MW | Turbine | VOC BACT Technology | Emission Limit on Hydrogen-Rich Fuel | | Emission Limit on Nat Gas | |
|---|---|---|---|---|---|---|---|---|
| | | | | | ppm | lb/MMBTU Hydrogen-Rich Fuel or Syngas Fuels | ppm | lb/MMBTU NG |
| HECA | CA | 250 | GE Model Number 7FB. | CO catalyst and GCP | 1[a] | 0.0016 | 2[a] | 0.0028 |
| Cash Creek Generation Station | KY | 630 | GE Model Number 7FB. | GCP | | N/A | | N/A |
| Edwardsport Generating Station | IN | 630 | GE Model Number 7FB. | GCP | | 0.0016[b] | | 0.0016 [b] |
| Taylorville Energy Center | IL | 630 (net) | GE Model Number 7FB. | GCP | | N/A | | N/A |

Notes:
[a] Parts per million by volume, dry basis, corrected to 15 percent $O_2$.
[b] Calculated from mass emissions rate of 3.3 lb/hr on hydrogen-rich fuel and natural gas.
MMBtu = million British thermal units
MW = megawatt
ppm = parts per million
VOC = volatile organic compound

## 6.2 Auxiliary CTG BACT Analysis

The following is the BACT analysis for the proposed auxiliary combustion turbine (Aux CTG). The proposed Aux CTG is a 103 megawatt natural-gas – fired GE LMS100® in a simple-cycle configuration, equipped with water injection for nitrogen oxide control. Post-combustion emission controls will include SCR and CO catalyst systems natural gas.

HECA proposed to apply the SJVAPCD BACT Guidelines for Gas Turbine > = 50 MW, Uniform Load without Heat Recovery, as the BACT for the Aux CTG unit.

### 6.2.1 Nitrogen Oxides BACT Analysis for the Auxiliary CTG

The achieved-in-practice or contained in the SIP BACT guideline for $NO_x$ is 5.0 ppmvd at 15 percent $O_2$, based on a 3-hour average with high-temperature SCR, or equal. The $NO_x$ emission limitation of 2.5 ppmvd at 15 percent $O_2$, (3-hour average) is categorized as technically feasible control technology.

HECA proposed the application of water injection as combustion process control, and SCR as post-combustion control to reduce $NO_x$ emission from the Auxiliary CTG down to 2.5 ppmvd at 15 percent $O_2$. As explained in the BACT analysis for the CTG/HRSG unit, water injection reduces the formation of thermal $NO_x$ in the combustion chamber by reducing the peak flame temperature, while SCR promotes the conversion of $NO_x$ to molecular nitrogen.

### 6.2.2 Carbon Monoxide BACT Analysis for the Auxiliary CTG

The achieved-in-practice or contained in the SIP BACT guideline for CO is 6.0 ppmvd at 15 percent $O_2$, based on a 3-hour average with oxidation catalyst, or equal, technology. HECA proposed the application of GCPs and CO catalyst as the control technology to reduce CO emission from the Auxiliary CTG down to 6.0 ppmvd at 15 percent $O_2$ as recommended in the BACT guideline.

### 6.2.3 Particulate Emissions BACT Analysis for the Auxiliary CTG

The achieved-in-practice or contained in the SIP BACT guideline for $PM_{10}$ is Air inlet cooler/filter, lube oil vent coalescer (or equal), and either PUC-regulated natural gas, LPG, or non-PUC regulated gas with < 0.75 grains Sulfur/100 dscf.

HECA auxiliary CTG is equipped with the following accessories to provide safe and reliable operation: evaporative coolers, inlet air filters, metal acoustical enclosure, duplex shell; and tube lube oil coolers for the turbine and generator, compressor water wash system, fire detection and protection system, hydraulic starting system, and compressor variable-bleed valve vent. In addition, this unit exclusively combusts PUC-grade natural gas with < 0.75 grain/100 dscf sulfur content. Therefore, the unit meets the recommended BACT emission limitation.

In addition to the recommendation from the BACT guideline, HECA proposed a $PM_{10}$ emission limit of 6 lbs/hour. This emission limit is proposed based on the lowest $PM_{10}$ BACT determination for a similar source from recently permitted power plants in California[2].

### 6.2.4 Sulfur Oxides BACT Analysis for the Auxiliary CTG

The achieved-in-practice or contained in the SIP BACT guideline for sulfur oxides is PUC-regulated natural gas, LPG, or non-PUC regulated gas with < 0.75 grain S/100 dscf. As mentioned in the previous section, the auxiliary CTG is proposed to be exclusively fueled by PUC-regulated gas with < 0.75 grain S/100 dscf. Therefore, this unit meets the recommended BACT.

### 6.2.5 Volatile Organic Compounds BACT Analysis for the Auxiliary CTG

The achieved-in-practice or contained in the SIP BACT guideline for VOCs is 2.0 ppmvd at 15 percent $O_2$, based on a 3-hour average with oxidation catalyst, or equal, technology. HECA proposed the application of GCPs and CO catalyst as the control technology to reduce VOC and CO emission from the Auxiliary CTG down to 2.0 ppmvd at 15 percent $O_2$ as recommended in the BACT guideline.

## 6.3 Cooling Towers Particulate Emissions BACT Analysis

There will be three cooling towers proposed for the Project: two cooling towers (gasification cooling tower and the ASU cooling tower) are associated with the gasification process, and the third cooling tower (power block cooling tower) is used by the power block. Compared to similar-sized combined-cycle power plants, the power block cooling duty is somewhat greater due to the heat integration with gasification resulting in the generation of additional steam for power production in the steam turbine. Each tower has a separate cooling water basin, pumps, and piping system, and operates independently. The cooling water will circulate through a mechanical draft-cooling tower that uses electric motor-driven fans to move the air into contact with the flow of the cooling water. The heat removed in the condenser will be discharged to the atmosphere by heating the air, and through evaporation of some of the cooling water.

The power block cooling tower is designed for an approximate capacity of 175,000 gallons per minute (gpm) of water, with an hourly circulation rate of 88 million lb/hr. The ASU and gasification block cooling water systems are similar in design to the power block cooling design, but they have substantially lower duties. The ASU cooling tower circulation rate is approximately 40,000 gpm, and the gasification cooling tower circulation rate is about 42,000 gpm.

All cooling towers are supplied with high-efficiency drift eliminators designed to reduce the maximum drift;; that is, the fine mist of water droplets entrained in the warm air leaving the cooling tower, to less than 0.0005 percent of the circulating water flow. Circulating water could range in TDS depending on makeup-water quality and tower operation. Therefore, $PM_{10}$ emissions would vary proportionately.

[2] Final Decision Panoche Energy Center (2007)

Wet (evaporative) cooling towers emit aqueous aerosol "drift" particles that evaporate to leave crystallized solid particles that are considered $PM_{10}$ emissions. The proposed control technology for $PM_{10}$ is high-efficiency drift eliminators to capture drift aerosols upstream of the release point to the atmosphere.

### *1. Identify Control Technologies*

The following particulate matter control technologies were evaluated for the proposed cooling towers:

*Potential Cooling Tower Control Technology*

- Drift Elimination System with limited TDS level

### *2. Evaluate Technical Feasibilities*

High-efficiency drift eliminators and limits on TDS concentrations in the circulating water are the techniques that set the basis for cooling tower BACT emission limits. The efficiency of drift eliminator designs is characterized by the percentage of the circulating water flow rate that is lost to drift. The drift eliminators to be used on the proposed cooling tower will be designed such that the drift rate is less than 0.0005 percent of the circulating water. Typical geometries for the drift eliminators include chevron-type.

There is no $PM_{10}$ BACT guideline for mechanical draft cooling towers in the SJVAPCD. However, the use of high-efficiency drift-eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is a commercially proven technique to reduce $PM_{10}$ emissions. Compared to "conventional" drift eliminators, advanced drift eliminators reduce the $PM_{10}$ emission rate by more than 90 percent.

In addition to the use of high-efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentrations of dissolved solids in the make-up water as the circulating water evaporates;; and secondarily, to the addition of anti-corrosion, anti-biocide additives.

### *3. Rank Control Technologies*

A drift elimination system is the only technically feasible control technology identified for the proposed cooling towers, and historically has been selected as BACT for other projects.

### *4. Evaluate Control Options*

The highest control efficiency to reduce the $PM_{10}$ emission from the proposed cooling towers involves the instillation of drift eliminators and adoption of TDS limit for the circulating water. Development of increasingly effective de-entrainment structures has resulted in equipment vendors' claims that a cooling tower may be specified to achieve drift release no higher than

0.0005 percent of the circulating water rate for the HECA project. This level of reduction has been approved in other recently permitted IGCC projects.

### *5. Select Control Technology*

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, drift elimination system is selected as BACT for the proposed cooling towers. The proposed cooling tower will be designed with a high-efficiency drift elimination system to minimize potential drift and particulate emissions, achieving a maximum drift of 0.0005 percent of the circulating water. This measure, along with a limit on the circulating water TDS, is considered to be the BACT option for particulate emissions from the cooling towers.

## 6.4 Auxiliary Boiler BACT Analysis

The auxiliary boiler will provide steam to facilitate CTG startup, and for other industrial purposes. The auxiliary boiler will be designed to burn pipeline-quality natural gas at the design maximum fuel flow rate of 142 MMBtu/hr (HHV). During normal operation, the auxiliary boiler may be kept in warm standby (steam sparged, no firing) or cold standby (no firing), and will not have emissions. The boiler will produce a maximum of about 100,000 pounds per hour of steam.

Pollutant emissions from natural gas boiler units include $NO_x$, $PM_{10}$, CO, $SO_2$, and VOCs. The auxiliary boiler emissions are based on 2,190 hours of operation per year. The applicant is proposing proper boiler design and operation, low-$NO_x$ combustors with FGR, and use of natural gas to be the BACT for the auxiliary boiler. This emission limitation is proposed to meet the SJVAPCD BACT Guidelines for greater than 20.0 MMBtu/hr natural-gas–fired boiler (base-loaded or with small load swings).

### *1. Identify Control Technologies*

The following criteria pollutant emissions control technologies were evaluated for the proposed auxiliary boilers:

*Potential Auxiliary Boiler Control Technology*

- Good Combustion Practices
- Low $NO_x$ combustor
- CO Oxidation Catalysts
- Low $NO_x$ combustor with Flue Gas Recirculation
- Selective Catalytic Reduction
- Selective Non-Catalytic Reduction

### 6.4.1 Nitrogen Oxides BACT Analysis for the Auxiliary Boiler

#### *2. Evaluate Technical Feasibilities*

- Low $NO_x$ Combustors

  Low $NO_x$ combustors reduce thermal $NO_x$ formation by regulating the distribution and mixing of fuel and air to control the stoichiometry and temperature of combustion. Historically, low $NO_x$ combustors have been selected as BACT for natural-gas–fired auxiliary boilers. Therefore, low-$NO_x$ combustor technology is technically feasible for the proposed auxiliary boiler.

- Low $NO_x$ Combustors with Flue Gas Recirculation

  FGR reduces boiler $NO_x$ emissions by recirculating a portion of the flue gas into the main combustion chamber. The increase in gas flow within the combustion chamber reduces the peak combustion temperature and oxygen in the combustion air/flue gas mixture, thereby reducing the formation of thermal $NO_x$. The application of FGR is typically in combination with low-$NO_x$ combustor technology and has been selected as BACT for some auxiliary boiler processes. Therefore, FGR is considered technically feasible for the proposed auxiliary boiler.

- Selective Catalytic Reduction

  SCR is a technology that achieves post-combustion reduction of $NO_x$ from flue gas within a catalytic reactor. The SCR process involves the injection of $NH_3$ into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of $NO_x$ to molecular nitrogen. SCR technology has been most commonly applied to pulverized-coal–generating units and to natural-gas–fired combustions turbines. However, no examples have been identified where an SCR has been applied to an auxiliary boiler. The auxiliary boiler will provide steam to facilitate CTG startup, and will be kept in warm standby (steam sparged, no firing) or cold standby during normal operation. This operation results in varying flue gas characteristics that may not be suitable for continuous SCR operation. Therefore, SCR is not technically feasible for the intended operation of the auxiliary boiler.

- Selective Non-Catalytic Reduction

  Selective non-catalytic reduction is a post-combustion $NO_x$ control technology in which a reagent ($NH_3$ or urea) is injected into the exhaust gases to react chemically with $NO_x$ to form elemental nitrogen and water without the use of a catalyst. The success of this process in reducing $NO_x$ emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas, which must occur within a narrow flue gas temperature zone (typically from 1,700°F to 2,000°F).

  The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to $NO_x$. Below the lower end of the temperature range, the reagent will not react with the $NO_x$, resulting in very high $NH_3$ slip concentrations ($NH_3$ discharge from the stack).

SNCR has never been applied in an auxiliary boiler unit, primarily because there are no flue gas locations within the process with the optimal requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Therefore, SNCR is not technically feasible for this unit.

### *3. Rank Control Technologies*

The use of low $NO_x$ combustor and flue gas recirculation is the only technically feasible control option identified for reducing $NO_x$ emissions. These control technologies are commonly used in combination and historically have been selected as BACT for other projects.

### *4. Select Control Technology*

Low-$NO_x$ combustor technology and flue gas recirculation have historically been selected as BACT for natural-gas–fired auxiliary boilers. These technologies are commonly used in combination to reduce $NO_x$ emissions in other recently permitted IGCC projects.

The proposed auxiliary boiler will be designed with a Low $NO_x$ combustor technology and flue gas recirculation, achieving a maximum $NO_x$ emission concentration of 9 ppm $NO_x$ at 3 percent $O_2$ on natural gas fuel.

### 6.4.2 Carbon Monoxide BACT Analysis for the Auxiliary Boiler

An inadequate degree of fuel mixing, lack of available oxygen, or low temperatures in the combustion zone are common causes of incomplete combustion that results in CO emissions. Fuel quality and good combustion practices can limit CO emissions. Good combustion practice has commonly been determined as BACT for natural-gas–fired auxiliary boilers. Post-combustion control technologies using catalytic reduction have also been employed in some processes to reduce CO and VOC emissions.

### *2. Evaluate Technical Feasibilities*

*Good Combustion Practices*

GCPs include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. Good combustion practice has historically been determined as BACT for CO and VOC emissions from auxiliary boilers, and is a technically feasible control strategy for the proposed auxiliary boiler.

*Oxidation Catalyst*

Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize CO and VOC into $CO_2$ or $H_2O$. The technology has most commonly been applied to natural-gas–

fired combustion turbines. No examples were identified where oxidation catalyst technology has been applied to an auxiliary boiler. Because of the low potential CO and VOC emission without an oxidation catalyst and the limited use of the proposed auxiliary boiler, the use of catalytic oxidation technology is determined to be infeasible.

#### *3. Rank Control Technologies*

Good combustion practice is the only feasible control strategy identified, and has historically been selected as BACT for CO emissions from the auxiliary boiler.

#### *4. Select Control Technology*

The use of good combustion practices has been selected as BACT for potential CO emission from the proposed auxiliary boiler. Boiler vendor information indicates that a CO worst-case hourly emission for the proposed auxiliary boiler is 50 ppmvd at 3 percent $O_2$.

### 6.4.3 Particulate Emissions, Sulfur Oxides, Volatile Organic Compounds BACT Analysis for the Auxiliary Boiler

For these pollutants, the commercially available control measures that are identified in the most stringent BACT determinations are use of low-sulfur, PUC natural gas, and GCP. Based on SJVAPCD BACT Guidelines for > 20.0 MMBtu/hr Natural-Gas–Fired Boiler (base-loaded or with small load swings), add-on controls were not implemented to achieve BACT limits for these pollutants.

Boiler vendor information indicates that the worst-case hourly emissions for this unit with these technologies would be 0.005 lb $SO_2$/MMBtu;; 0.004 lb VOC /MMBtu; and 0.005 lb $PM_{10}$/MMBtu. These rates, or corresponding lb/hour emission rates, are proposed as BACT limits for the auxiliary boiler emission unit.

## 6.5 Diesel Engines BACT Analysis

The Project will include two 2,800 HP standby diesel generators and one 556 HP, standby firewater pump. HECA proposed to apply the SJVAPCD BACT Guidelines for Emergency Diesel I.C. Engine = or > 400 hp as the BACT for the standby diesel generator engines, and SJVAPCD BACT Guidelines for Emergency Diesel I.C. Engine Driving a Fire Pump as the BACT for the standby firewater pump engine. The BACT emission limits will be achieved by the following control effort.

- Low Sulfur Fuel Selection

  The diesel engines will exclusively combust ultra-low sulfur diesel fuel. $SO_2$ emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur.

- Clean Combustion Process Selection

The engines will meet USEPA Tier 4 emissions standards for 2011 model equipment.

Standby diesel generator engine: 0.3 g/bhp-hr NMHC; 0.5 g/bhp-hr $NO_x$; 2.6 g/bhp-hr CO; 0.07 g/bhp-hr PM

Standby firewater pump engine: 0.14 g/bhp-hr NMHC; 1.5 g/bhp-hr $NO_x$; 2.6 g/bhp-hr CO; 0.015 g/bhp-hr PM

- Restricted Operating Hours

  The standby diesel generators will operate less than 50 hours per year per engine for non-emergency purposes such as: routine testing, maintenance, and inspection purposes. The fire pump will operate than less than 50 hours per year per engine for non-emergency purposes.

### 6.5.1 BACT Analysis for the Standby Diesel Generators

The achieved-in-practice or contained in the SIP BACT guideline for $NO_x$ is certified emissions of 6.9 g/bhp-hr or less. The proposed control of using engines that meet USEPA Tier 4 emissions standards for 2011 model equipment will meet this BACT limit with 0.5 g/bhp-hr $NO_x$. Although it is technically feasible to install add-on $NO_x$ control, this option is cost prohibitive due to the emergency nature of the engine operations.

The achieved-in-practice or contained in the SIP BACT guideline for CO is 2.0 g/bhp-hr. The vendor emission factor for the diesel engines guaranteed 0.29 g/bhp-hr of CO emission. This emission limit is substantially below the required BACT limit. Although it is feasible to install a CO oxidation catalyst to further reduce CO emissions from the engines, the cost for oxidation catalyst for CO control will be prohibitive, given the low number of routine operating hours per year of the engines.

The achieved-in-practice or contained in the SIP BACT guideline for $PM_{10}$ is 0.1 gram/bhp-hr (if TBACT is triggered) or 0.4 g/bhp-hr (if TBACT is not triggered). The proposed control of using engines that meet USEPA Tier 4 emissions standards for 2011 model equipment will meet this BACT limit with 0.07 g/bhp-hr PM.

The achieved-in-practice or contained in the SIP BACT guideline for sulfur oxides is low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-Sulfur Diesel fuel (15 ppmw sulfur or less). The standby diesel generator engines will exclusively combust ultra-low sulfur diesel fuel. $SO_2$ emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur.

There is no numerical emission limit achieved in practice or contained in the SIP BACT guideline for VOC. The proposed control of using engines that meet USEPA Tier 4 emissions standards for 2011 model equipment proposed a BACT limit with 0.3 g/bhp-hr VOC for this unit.

### 6.5.2 BACT Analysis for the Firewater Pump Diesel Engine

The achieved-in-practice or contained in the SIP BACT guideline for $NO_x$ is certified emissions of 6.9 g/bhp-hr or less. The proposed control of using engines that meet USEPA Tier 4 emissions standards for 2011 model equipment will meet this BACT limit with 1.5 g/bhp-hr $NO_x$. Although it is technically feasible to install add-on $NO_x$ control, this option is cost prohibitive due to the emergency nature of the fire/water pump engine operations.

There is no numerical emission limit achieved in practice or contained in the SIP BACT guideline for CO. The proposed control of using engines that meet USEPA Tier 4 emissions standards for 2011 model equipment proposed a BACT limit with 2.6 g/bhp-hr CO for this unit. Although it is feasible to install CO oxidation catalyst to further reduce CO emissions from the engines, the cost for an oxidation catalyst for CO control will be prohibitive, given the low number of routine operating hours per year of the fire water pump.

The achieved-in-practice or contained in the SIP BACT guideline for $PM_{10}$ is 0.1 grams/bhp-hr (if TBACT is triggered) or 0.4 grams/bhp-hr (if TBACT is not triggered). The proposed control of using engines that meet USEPA Tier 4 emissions standards for 2011 model equipment will meet this BACT limit with 0.015 g/bhp-hr PM.

The achieved-in-practice or contained in the SIP BACT guideline for sulfur oxides is low-sulfur diesel fuel (500 ppmw sulfur or less) or ultra-low sulfur diesel fuel (15 ppmw sulfur or less). The firewater-pump diesel engine will exclusively combust ultra-low sulfur diesel fuel. $SO_2$ emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur.

No numerical emission limit is achieved in practice or contained in the SIP BACT guideline for VOC. The proposed control of using engines that meet USEPA Tier 4 emissions standards for 2011 model equipment proposed a BACT limit with 0.14 g/bhp-hr VOC for this unit.

## 6.6 Gasification Flare BACT Analysis

The gasification block will be provided with a relief system and associated gasification flare to safely dispose of gasifier streams during startup, shutdown, and unplanned upsets or emergency events, syngas during AGR startup, hydrogen-rich gas during short-term emergency combustion turbine outages, or other various streams within the Project during other unplanned upsets or equipment failures. Note that sulfur compounds will be treated upstream of the gasification flare header by the Gasification Amine Absorber.

Two flare-control technologies were evaluated for the proposed facility: an elevated flare, and an enclosed ground flare. Elevated flare technology uses a stack to vent combustible process gases to a combustor located at the top, resulting in an open flame at the stack discharge. Elevated flares provide for greater dispersion of heat and combustion products than ground flares. Elevated flares are the most common technology used by refinery, steel, and chemical industries, and are used by operational and recently permitted IGCC projects.

Compared to an elevated flare, an enclosed ground flare offers reduced noise, reduced visual impact, potentially, and better CO destruction. However, an enclosed ground flare poses potentially decreased dispersion of combustion gases and increased reliability concerns and have never been installed on any IGCC plants and so are considered unproven technology in this application with an associated risk. Elevated flares are used extensively with IGCC applications and therefore, the gasification block will be designed with an elevated flare to safely dispose of gasifier startup gases, hydrogen-rich fuel during AGR startup, hydrogen-rich gas during short-term emergency combustion turbine outages, or other various streams within the Project during other unplanned upsets or equipment failures. The low-pressure sour syngas sent to the flare from the gasification and shift units during shutdown depressurizing operations is first scrubbed in the Gasification Amine Absorber to remove essentially all of the sulfur bearing compounds. Flaring of untreated syngas or other streams within the plant would only occur as an emergency safety measure during unplanned plant upsets or equipment failures.

The gasification flare will emit criteria pollutants that are products of combustion. However, the chemical compositions of the predominant gaseous fuels that would be flared, i.e., syngas and natural gas, result in very low emissions of $PM_{10}$, $SO_2$, and VOC. For the syngas case, there is very little unoxidized carbon in the fuel, which limits the formation of particulate matter during combustion even below the rate for natural gas. Formation of $SO_2$ is limited by the pre-treatment of the syngas flare stream, and the inherently low sulfur content of pipeline natural gas.

### *1. Identify Control Technologies*

The following control technologies were evaluated for the proposed gasification flare:

- Clean pilot fuel (Natural gas) and Good Combustion Practices
- Low $NO_x$ Combustor
- Add-On Controls

### *2. Evaluate Technical Feasibilities*

- Clean pilot fuel (Natural Gas) and Good Combustion Practices

  A certain level of flame temperature control can be exercised for the gasification flare by implementing fuel/air ratio control. Flare BACT options that have been achieved in practice in California (e.g., CAPCOA BACT Clearinghouse) indicate a natural gas pilot and “proper burner management and monitoring” are used to control the emissions of CO, VOCs and $NO_x$.

- Low-$NO_x$ Combustor

  Low-$NO_x$ combustor and ultralow $NO_x$ combustor technology alter air-to-fuel ratio in the combustion zone by staging the introduction of the air to promote a “lean-premixed” flame. This results in lower combustion temperatures and reduced $NO_x$ formation. Such designs are not available for elevated flares, that do not have a confined combustion zone, which would allow staged introduction of fuel and air streams. Therefore, this control technology is not feasible for the proposed gasification flare.

- Add-On Controls

  The gasification block flare is not a candidate for add-on abatement systems. It is generally recognized in the chemical process industries that adoption of add-on control can impede the ability of a flare to respond to unexpected upset conditions. Therefore, this control technology is not feasible for the proposed gasification flare.

For plant safety, the flare must provide a "fail-safe" that is available regardless of the functioning of pollution control devices.

### *3. Rank Control Technologies*

The use of natural gas as pilot fuel and good combustion practices were identified as the only technically feasible criteria pollutant emissions control technologies applicable to the proposed gasification flare.

### *4. Evaluate Control Options*

As determined in the last section, the use of natural gas as pilot fuel and good combustion practices are the only feasible control strategy identified. Based on review of SJVAPCD BACT guideline, there is no BACT determination source category for flare that supports the gasification process.

### *5. Select Control Technology*

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, use of natural gas as pilot fuel and GCPs are selected as BACT for the proposed gasification flare. The measure, along with natural gas pilot and processes flare gas for non-emergency operation are considered to be the best available control option for criteria pollutant emissions from the gasification flare. The proposed control and criteria pollutant emissions for the gasification flare are summarized in Table 6-7.

## 6.7 Sulfur Recovery System BACT Analysis

The sulfur recovery system is designed to process acid gas streams from the AGR system and IGCC process into an elemental sulfur by-product. Sulfur is removed from the processing facility through a sulfur complex which consists of a Claus unit (thermal stage) plus catalytic converters otherwise known as the SRU, and a Tail Gas Treating Unit (TGTU). The SRU is a totally enclosed process with no discharges to the atmosphere. The tail gas from the SRU is composed mostly of carbon dioxide, water vapor, and sulfur vapor with trace amounts of $H_2S$ and $SO_2$. The tail gas is routed to the TGTU where the majority of the sulfur is recovered. The overhead of the TGT Unit is combined with the much larger product $CO_2$ stream and exported offsite for oil reservoir injection.

**Table 6-7**
**Gasification Flare Total Criteria Pollutant Emissions**

| Pollutant | Emissions | | | |
|---|---|---|---|---|
| | Pilot (ton/yr) | Start-Up/ Shut-Down (ton/yr) | Total (ton/qtr) | Total (ton/yr) |
| $NO_x$ | 0.26 | 4.04 | 1.08 | 4.3 |
| CO | 0.18 | 48.65 | 12.21 | 48.8 |
| VOC | 0.003 | 0.00 | 0.001 | 0.003 |
| $SO_2$ | 0.004 | 0.00 | 0.001 | 0.004 |
| $PM_{10} = PM_{2.5}$ | 0.01 | 0.00 | 0.002 | 0.01 |

Notes:
CO = carbon monoxide
$NO_x$ = oxides of nitrogen
$PM_{10} = PM_{2.5}$ = particulate matter 10 microns in diameter or smaller and is assumed to equal $PM_{2.5}$ = particulate matter 10 microns in diameter
$SO_2$ = sulfur dioxide
VOC = volatile organic compound

The proposed sulfur process facility consists of 2 by 50 percent SRUs, and 1 by 100 percent TGTU. The SRU and TGTU give an overall sulfur recovery efficiency of 99.9 percent. Associated with the operation of the sulfur recovery system, HECA proposed the integral use of two elevated flares, a caustic scrubber, and a thermal oxidizer as control devices to provide for the safe and efficient destruction of combustible gas streams. These control devices are primarily used intermittently during short-term periods of startup, shutdown, and malfunction operations.

### 1. *Identify Control Technologies*

The following control technologies were evaluated for the proposed Sulfur Recovery System:

- Thermal Oxidizer
- Flare
- Caustic Scrubber

### 2. *Evaluate Control Technologies*

- Thermal Oxidizer

  In the thermal oxidizer, the TGTU tail gas and other oxidizing streams are subjected to a high temperature and a sufficient residence time to cause an essentially complete destruction of reduced sulfur compounds such as $H_2S$. The thermal oxidizer uses natural gas to reach the necessary operating temperature for optimal thermal destruction. The thermal oxidizer also controls emissions from various systems during normal operations, including the sulfur pit vent. A continuous natural gas pilot will be in service on both controls. The flare and thermal oxidizer are the only control technologies identified that are capable of controlling the variable potential gas streams associated with the sulfur recovery process and the startup, shutdown, and malfunction of the integrated IGCC systems.

Good thermal oxidizer design includes optimization of parameters that maintain efficiency, such as temperature, residence time, and the mixing of gas streams in the combustion zone. The proposed thermal oxidizer will use natural gas for preheating and to facilitate the combustion of process gases in the thermal oxidizer. Implementation of these elements into the design and operation of the thermal oxidizer, in combination with the use of a natural-gas pilot flame, will support a thermal oxidizer control technology that minimizes incomplete combustion, which directly correlates to potential criteria pollutant emissions.

- Flare

  Emissions from the IGCC gas cleanup process cannot be directed to certain control systems and/or the combustion turbines during startup and shutdown operations, or during operational malfunctions. Directly venting these emissions to the atmosphere could result in very high concentrations of $SO_2$, CO, VOCs, $NO_x$, and/or $H2_SO_4$ being released. In this case, two elevated flares are selected to accommodate the variability inherent in these operations: Sulfur Recovery Unit Flare, and Rectisol Flare.

  An SRU Flare will be used to safely dispose of gas streams containing sulfur during startup and shutdown, and gas streams containing sulfur during unplanned upsets or emergency events. Acid gas derived from the AGR, gasification unit, and SWS overhead is normally routed to the SRU for recovery as elemental sulfur. During cold plant startup of the gasifiers, AGR, and Shift units, these acid-gas streams will be diverted to the SRU Flare Header for a short time. To reduce the emissions of sulfur compounds to the environment during SRU or TGTU shutdown, the acid gas is routed to the Emergency Caustic Scrubber, where the sulfur compounds are absorbed with caustic solution. After scrubbing, the gas is then routed to the elevated SRU Flare Stack.

  Enclosed ground flares have the potential to minimize flame appearance and provide a setting for monitoring post-combustion gas streams. However, they have not been proven for the proposed facility because of reliability concerns.

  Elevated flares are used extensively with IGCC applications and therefore, are considered proven technology. The gasification block will be designed with an elevated flare.

- Caustic Scrubber

  During cold plant startup of the gasification block, acid-gas streams will be diverted to a caustic scrubber prior to being directed to the elevated flare for a short time. The caustic scrubber removes $H_2S$ from the acid gas stream with an anticipated scrubbing efficiency of at least 99.6 percent sulfur removal.

### *3. Select Control Technology*

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As discussed, the use of flares, thermal oxidizer, and caustic scrubber are the proposed technologies designed to control criteria pollutant emissions from the sulfur recovery system, in addition to an efficient IGCC process design. These technologies complement one another, and may operate in combination with each other.

Including the proposed control system to provide for the safe and efficient destruction of combustible sulfur-rich acid-gas streams, the emissions from the sulfur recovery system are categorized into three emission sources of tail gas thermal oxidizer, SRU flare and Rectisol flare (elevated flares with natural gas assist). Each emission source has its own emission control measure to reduce its criteria pollutant emissions. The proposed control and criteria pollutant emissions for the sulfur recovery system are summarized in Table 6-8.

**Table 6-8**
**Sulfur Recovery System Emissions**

| Pollutant | Thermal Oxidizer Emissions (lb/MMBtu, HHV) | SRU Flare Emissions | | | | Rectisol Flare Emissions* | | |
|---|---|---|---|---|---|---|---|---|
| | | Pilot (ton/yr) | Start-Up/ Shut-Down (ton/yr) | Total (ton/qtr) | Total (ton/yr) | Pilot (ton/yr) | Total (ton/qtr) | Total (ton/yr) |
| $NO_x$ | 0.13 | 0.16 | 0.0130 | 0.04 | 0.2 | 0.16 | 0.04 | 0.2 |
| CO | 0.04 | 0.11 | 0.0086 | 0.03 | 0.1 | 0.11 | 0.03 | 0.1 |
| VOC | 0.0070 | 0.002 | 0.0001 | 0.000 | 0.002 | 0.002 | 0.000 | 0.002 |
| $SO_2$ | See Below | 0.003 | 0.05 | 0.014 | 0.1 | 0.003 | 0.001 | 0.003 |
| $PM_{10}$ = $PM_{2.5}$ | 0.008 | 0.004 | 0.0003 | 0.001 | 0.004 | 0.004 | 0.001 | 0.004 |

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

Notes:

CO = carbon monoxide
$NO_x$ = oxides of nitrogen
$PM_{10}$ = $PM_{2.5}$ = particulate matter 10 microns in diameter or smaller and is assumed to equal $PM_{2.5}$ = particulate matter 10 microns in diameter
$SO_2$ = sulfur dioxide
VOC = volatile organic compound
* = Rectisol Flare will be used exclusively for emergency events. During normal plant operation, Rectisol Flare will have a natural-gas–fired pilot light (there is no planned operation expected for this source).

## 6.8 $CO_2$ Vent BACT Analysis

The Project will produce electricity while substantially reducing greenhouse gas emissions by capturing $CO_2$. At least 90 percent of the carbon in the raw syngas will be captured in a high-purity carbon dioxide stream during steady-state operation, which will be compressed and transported by pipeline off site for injection into deep underground oil reservoirs for enhanced oil recovery and sequestration.

A $CO_2$ vent stack will allow for infrequent venting of produced $CO_2$ from the AGR and TGTU when the $CO_2$ injection system is unavailable, unable to export, or other upset condition. The $CO_2$ vent will enable HECA to operate, rather than be disabled, by brief periods of gasifier shutdown and subsequent gasifier restart. The $CO_2$ vent exhaust stream will be nearly all $CO_2$, with small amounts of CO, VOC, and $H_2S$.

Due to the infrequent nature of the venting event, the option of using add-on control technology is cost prohibitive for this emission point. In order to reduce the impact of this infrequent venting event, good engineering practice stack height, limited venting duration, and vent gas concentration limits are selected as BACT for this source.

HECA proposed a maximum of 504 hours of venting duration for this unit. The pollutant concentrations in the vent gas are limited to 1,000 ppm for CO, 40 ppm for VOCs, and 10 ppm for $H_2S$ to reduce the overall impact of the venting event.

### *Good Engineering Practice Stack Height*

The USEPA provides specific guidance for determining the Good Engineering Practice (GEP) stack height and for determining whether building downwash will occur in the *Guidance for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations*). GEP is defined as "the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles."

The GEP definition is based on the observed phenomenon of atmospheric flow in the immediate vicinity of a structure. It identifies the minimum stack height at which significant adverse aerodynamics (downwash) are avoided. The U.S. EPA GEP stack height regulations specify that the GEP stack height is calculated in the following manner:

$$H_{GEP} = H_B + 1.5L$$

where:

$H_B$ = the height of adjacent or nearby structures;; and

L = the lesser dimension (height or projected width) of the adjacent or nearby structures.

The regulations also specify that the creditable stack height for modeling purposes is either the GEP stack height as calculated, or a de minimis height of 65 meters.

A 260-foot stack height was chosen to satisfy HEI's inherently safe design practices to minimize ground-level $CO_2$ concentrations in the event of a $CO_2$ vent under very low wind speeds.

## 6.9 Gasifier Warming (Refractory Heaters) BACT Analysis

HECA proposed to install three natural-gas–fired gasification refractory heaters, each rated at 18 MMBtu/hr. Each of the three gasification trains will have one natural-gas fired combustor used to warm the gasification refractory to facilitate startup. The heaters are restricted to operate for gasifier startup with maximum total gasifier warming duration of 1,800 hours per year during mature operations.

No examples were found regarding the application of LAER for the case-specific emissions associated with natural gas combustion. To control criteria pollutant emissions from the heaters' natural gas combustion, HECA selected GCPs, natural-gas fuel, and restricted operating hours as BACT for the heaters. The total of potential PM and VOC emissions from the gasifiers are negligible (less than 0.2 tons/year). Therefore, the use of natural gas was determined to be LAER for the heaters. Good combustion practices will optimize the performance of the combustor, thereby minimizing the emission of $NO_x$ and CO. Because the heaters will only combust natural gas, the potential for $SO_2$, VOC, and PM emissions is minimized. The proposed BACT/LAER emission rates for each gasifier refractory heater are presented in Table 6-9.

**Table 6-9**
**Gasifier Warming (Refractory Heater) Emissions**

| Pollutant | Emission Limit |
|---|---|
| $NO_x$ | 0.11 lb/MMBtu, HHV |
| CO | 0.09 lb/MMBtu, HHV |
| PM/ $PM_{10}$ | 0.008 lb/MMBtu, HHV |
| $SO_2$ | 0.002 lb/MMBtu, HHV (12.65 ppm) |
| VOC | 0.007 lb/MMBtu, HHV |

Notes:
CO = carbon monoxide
$NO_x$ = oxides of nitrogen
PM/ $PM_{10}$ = particulate matter/ particulate matter 10 microns in diameter
$SO_2$ = sulfur dioxide
VOC = volatile organic compound

## 6.10 Feedstock Handling System BACT Analysis

Two major IGCC feedstock with particulate emission potential are petcoke and fluxant. Petcoke will be delivered to the plant via truck from refineries in the Los Angeles, Santa Maria, or Bakersfield areas, and/or other regional sources. Fluxant will be delivered to the Project Site via truck from regional sources. The transportation and preparation processes related to the feedstock have a potential to emit particulate matter to the atmosphere. The following is the BACT analysis for the proposed feedstock-handling system in HECA.

### 6.10.1 Particulate Matter BACT Analysis for the Feedstock-Handling System

Because the feedstock preparation processes will be within an enclosed conveyor system, a forced air dust collection system is the most appropriate and common control technology for particulate matter emission control from the emission points.

- Truck Unloading
- Petcoke/coal Silos (filling)
- Mass Flow Bins (in/out)
- Petcoke/coal Silos (loadout)
- Crusher Inlet/Outlet
- Fluxant Bins (filling)

HECA selected dust collection systems consisting of hoods and baghouses as BACT to control particulate emissions from the aforementioned emission points. HECA will have six bag houses, with the maximum dust collector PM emission rate based on expected supplier guarantee of 0.005 grain/scf outlet dust loading.

AA dust collection system using baghouses has been proposed as BACT in other operating and recently permitted IGCC projects. The proposed emission limitation represents a removal efficiency that is comparable with the emission achieved in practice at currently operating IGCC units, and the lowest recently permitted IGCC units.

## 7.0 REFERENCE

Korens, Nick, et al., 2002. "Process Screening Analysis of Alternative Gas Treating and Sulfur Removal for Gasification." U.S. Department of Energy. National Energy Technology Laboratory. December 2002. SFA Pacific, Inc. Mountain View, California. Available online at <http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/SFA%20Pacific_Process%20Screening%20Analysis_Dec%202002.pdf>

IGCC Permits and Applications for Cash Creek Generating Station, Edwardsport Generating Station, and Taylorville Energy Center.

CEC, 2007. Final Decision Panoche Energy Center.

# Appendix B
# Emissions

## Modeling Parameters for Emission Sources — Summary

*Hydrogen Energy, Inc*
*HECA Project*

*6/30/2009*

| 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 | Auxiliary CTG 100% Load | Auxiliary CTG 75% Load | Auxiliary CTG 50% Load |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **English Units** | | | | | | | | | | | |
| Stack height above grade[(1)] | ft | 213 | 213 | 213 | 213 | 213 | 213 | 213 | 110 | 110 | 110 |
| Stack diameter | ft | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 16 | 16 | 16 |
| Stack outlet temperature | $^{o}$F | 200 | 190 | 180 | 180 | 170 | 160 | 190 | 740 | 740 | 760 |
| Stack exit flow, act | $ft^3/s$ | 19,900 | 16,300 | 13,400 | 16,700 | 14,300 | 11,900 | 18,300 | 14,100 | 12,400 | 10,100 |
| **Metric Units** | | | | | | | | | | | |
| Stack height above grade[(1)] | m | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 65.0 | 33.5 | 33.5 | 33.5 |
| Stack diameter | m | 6.1 | 6.1 | 6.1 | 6.1 | 6.1 | 6.1 | 6.1 | 4.9 | 4.9 | 4.9 |
| Stack outlet temperature | K | 366.5 | 360.9 | 355.4 | 355.4 | 349.8 | 344.3 | 360.9 | 666.5 | 666.5 | 677.6 |
| Stack exit flow, act | $m^3/s$ | 563.5 | 461.6 | 379.4 | 472.9 | 404.9 | 337.0 | 518.2 | 399.3 | 351.1 | 286.0 |
| Stack Area | $m^2$ | 29.2 | 29.2 | 29.2 | 29.2 | 29.2 | 29.2 | 29.2 | 18.7 | 18.7 | 18.7 |
| Stack exit velocity, act | m/s | 19.3 | 15.8 | 13.0 | 16.2 | 13.9 | 11.5 | 17.8 | 21.4 | 18.8 | 15.3 |

| 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 | 9.8 | 2 | 1.3 | 2.5 | 1.0 | 30 | 1.2 | 0.7 | 3.5 |
| Stack outlet temperature | $^{o}$F | 300 | (NA) | (NA) | (NA) | 1200 | 150 | 75 | 760 | 850 | 65 |
| Stack exit flow, act | $ft^3/s$ | 480 | 0.5/900 | 0.3/36 | 0.3 | 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 | 3.0 | 0.6 | 0.4 | 0.8 | 0.3 | 9.1 | 0.4 | 0.2 | 1.1 |
| Stack outlet temperature | K | 422.0 | (NA) | (NA) | (NA) | 922.0 | 338.7 | 297.0 | 677.6 | 727.6 | 291.5 |
| Stack exit flow, act | $m^3/s$ | 13.6 | 0.01/25.49 | 0.01/1.02 | 0.01 | 3.4 | 1.9 | 523.9 | 7.1 | 1.7 | 50.0 |
| Stack Area | $m^2$ | 1.5 | 7.0 | 0.3 | 0.1 | 0.5 | 0.1 | 65.7 | 0.1 | 0.0 | 0.9 |
| Stack exit velocity, act | m/s | 9.2 | 0.001/3.64 | 0.03/3.4 | 0.1 | 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) Based on gasifier startup; stack parameters estimated from a previous project, to be confirmed by current flare suppliers.
(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 normal pilot gas, the second value is the maximum startup heat release (Rectisol Flare has no planned operation than 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

## Modeling Parameters for Emission Sources — Summary

*Hydrogen Energy, Inc*
*HECA Project*

*6/30/2009*

| Parameter | | Feed Stock - Dust Collection Units | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 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 | 314 | 459 | 428 | 314 | 368 | 428 | | | |
| Stack height above grade | ft | 25 | 170 | 139 | 25 | 79 | 139 | | | |
| Stack diameter | ft | 1.7 | 2.7 | 1.8 | 1.4 | 1.4 | 0.8 | | | |
| Stack outlet temperature (1) | $^oF$ | 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 | 7.6 | 51.8 | 42.4 | 7.6 | 24.1 | 42.4 | | | |
| 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 | 15.0 | 14.9 | 14.7 | 15.7 | 15.1 | 14.2 | | | |

(1) Assume ambient temperature

## Total Project Modeling Emission Rates — Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

### Modeling Worst-Case 1 hr Emissions

| | CTG/HRSG Maximum [1] | Auxiliary CTG | Cooling Towers [2] | | | Auxiliary Boiler | Emergency Generators [3] | Fire Water Pump | Gasification Flare | SRU Flare | Rectisol Flare | Tg Thermal Oxidizer | $CO_2$ Vent | Gasifier [4] | Feedstock | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Power Block | Process Area | ASU | | | | | | | | | | DC-1 | DC-2 | DC-3 | DC-4 | DC-5 | DC-6 |
| | (g/sec) | (g/sec) | (g/sec/cell) | (g/sec/cell) | (g/sec/cell) | (g/sec) | (g/sec/gen) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) |
| NOx | 21.0 | 2.6 | -- | -- | -- | 0.2 | 0.4 | 0.2 | 7.9 | 0.544 | 0.005 | 0.6 | -- | 0.2 | -- | -- | -- | -- | -- | -- |
| CO | 211.6 | 8.7 | -- | -- | -- | 0.7 | 0.2 | 0.4 | 113.4 | 0.363 | 0.003 | 0.5 | 53.4 | 0.2 | -- | -- | -- | -- | -- | -- |
| $SO_2$ | 0.9 | 0.2 | -- | -- | -- | 0.04 | 0.004 | 0.0007 | 0.0001 | 2.19 | 0.0001 | 0.3 | -- | 0.00 | -- | -- | -- | -- | -- | -- |
| $H_2S$ | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 0.6 | -- | -- | -- | -- | -- | -- | -- |

(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.
(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, only one gasifier warming will be operational at any one time.

### Modeling Worst-Case 3 hr Emissions

| | CTG/HRSG Maximum [1] | Auxiliary CTG | Cooling Towers [2] | | | Auxiliary Boiler | Emergency Generators [3] | Fire Water Pump | Gasification Flare | SRU Flare | Rectisol Flare | Tg Thermal Oxidizer | $CO_2$ Vent | Gasifier [4] | Feedstock | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Power Block | Process Area | ASU | | | | | | | | | | DC-1 | DC-2 | DC-3 | DC-4 | DC-5 | DC-6 |
| | (g/sec) | (g/sec) | (g/sec/cell) | (g/sec/cell) | (g/sec/cell) | (g/sec) | (g/sec/gen) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) |
| $SO_2$ | 0.9 | 0.2 | -- | -- | -- | 0.04 | 0.002 | 0.0005 | 0.0001 | 2.19 | 0.00 | 0.3 | -- | 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.
(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, only one gasifier warming will be operational at any one time.

### Modeling Worst-Case 8 hr Emissions

| | CTG/HRSG Maximum [1] | Auxiliary CTG | Cooling Towers [2] | | | Auxiliary Boiler | Emergency Generators [3] | Fire Water Pump | Gasification Flare | SRU Flare | Rectisol Flare | Tg Thermal Oxidizer | $CO_2$ Vent | Gasifier [4] | Feedstock | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Power Block | Process Area | ASU | | | | | | | | | | DC-1 | DC-2 | DC-3 | DC-4 | DC-5 | DC-6 |
| | (g/sec) | (g/sec) | (g/sec/cell) | (g/sec/cell) | (g/sec/cell) | (g/sec) | (g/sec/gen) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) |
| CO | 164.9 | 2.7 | -- | -- | -- | 0.7 | 0.06 | 0.1 | 113.4 | 0.138 | 0.003 | 0.5 | 53.4 | 0.2 | -- | -- | -- | -- | -- | -- |

(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.
(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, only one gasifier warming will be operational at any one time.

## Total Project Modeling Emission Rates — Summary

*Hydrogen Energy, Inc*
*HECA Project*

*6/30/2009*

### Modeling Worst-Case 24 Hour Emission Rate

| | CTG/HRSG Maximum [(1)] | Auxiliary CTG | Cooling Towers [(2)] | | | Auxiliary Boiler | Emergency Generators [(3)] | Fire Water Pump | Gasification Flare | SRU Flare | Rectisol Flare | Tg Thermal Oxidizer | $CO_2$ Vent | Gasifier [(4)] | Feedstock | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Power Block | Process Area | ASU | | | | | | | | | | DC-1 | DC-2 | DC-3 | DC-4 | DC-5 | DC-6 |
| | (g/sec) | (g/sec) | (g/sec/cell) | (g/sec/cell) | (g/sec/cell) | (g/sec) | (g/sec/gen) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) |
| $SO_2$ | 0.9 | 0.2 | -- | -- | -- | 0.04 | 0.0003 | 0.0001 | 0.0001 | 0.2742 | 0.0001 | 0.3 | -- | 0.00 | -- | -- | -- | -- | -- | -- |
| $PM_{10}$ | 3.0 | 0.8 | 0.038 | 0.030 | 0.028 | 0.09 | 0.002 | 0.0002 | 0.0002 | 0.0018 | 0.0001 | 0.02 | -- | 0.02 | 0.030 | 0.076 | 0.041 | 0.026 | 0.025 | 0.003 |
| $PM_{2.5}$ [(5)] | 3.0 | 0.8 | 0.023 | 0.018 | 0.017 | 0.09 | 0.002 | 0.0002 | 0.0002 | 0.0018 | 0.0001 | 0.02 | -- | 0.02 | 0.009 | 0.022 | 0.012 | 0.008 | 0.007 | 0.001 |

(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.

(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, only one gasifier warming will be operational at any one time.

(5) Where $PM_{10}$ = $PM_{2.5}$, it is assumed that $PM_{10}$ is 100% $PM_{2.5}$

### Modeling Annual Average Emission Rate

| | CTG/HRSG Maximum [(1)] | Auxiliary CTG | Cooling Towers [(2)] | | | Auxiliary Boiler | Emergency Generators [(3)] | Fire Water Pump | Gasification Flare | SRU Flare | Rectisol Flare | Tg Thermal Oxidizer | $CO_2$ Vent | Gasifier [(4)] | Feedstock | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Power Block | Process Area | ASU | | | | | | | | | | DC-1 | DC-2 | DC-3 | DC-4 | DC-5 | DC-6 |
| | (g/sec) | (g/sec) | (g/sec/cell) | (g/sec/cell) | (g/sec/cell) | (g/sec) | (g/sec/gen) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) | (g/sec) |
| $NO_X$ | 4.8 | 0.5 | -- | -- | -- | 0.05 | 0.002 | 0.003 | 0.1 | 0.005 | 0.005 | 0.3 | -- | 0.05 | -- | -- | -- | -- | -- | -- |
| CO | 4.3 | 0.8 | -- | -- | -- | 0.2 | 0.001 | 0.005 | 1.4 | 0.003 | 0.003 | 0.26 | 3.1 | 0.04194 | -- | -- | -- | -- | -- | -- |
| VOC | 0.9 | 0.1 | -- | -- | -- | 0.02 | 0.0005 | 0.0002 | 0.0001 | 0.00005 | 0.00005 | 0.01 | 0.1 | 0.00326 | -- | -- | -- | -- | -- | -- |
| $SO_2$ | 0.8 | 0.1 | -- | -- | -- | 0.01 | 0.00002 | 0.00001 | 0.0001 | 0.0016 | 0.0001 | 0.3 | -- | 0.00095 | -- | -- | -- | -- | -- | -- |
| $PM_{10}$ | 2.9 | 0.4 | 0.036 | 0.028 | 0.027 | 0.02 | 0.0001 | 0.00003 | 0.0002 | 0.0001 | 0.0001 | 0.01 | -- | 0.004 | 0.006 | 0.015 | 0.036 | 0.023 | 0.022 | 0.0004 |
| $PM_{2.5}$ [(5)] | 2.9 | 0.4 | 0.022 | 0.017 | 0.016 | 0.02 | 0.0001 | 0.00003 | 0.0002 | 0.0001 | 0.0001 | 0.01 | -- | 0.004 | 0.002 | 0.004 | 0.011 | 0.0068 | 0.007 | 0.0001 |
| $H_2S$ | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 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.

(4) There are three gasifiers. The modeling rate shown is per individual gasifier. However, only one gasifier warming will be operational at any one time.

(5) Where $PM_{10}$ = $PM_{2.5}$, it is assumed that $PM_{10}$ is 100% $PM_{2.5}$

## Total Annual Project Emissions — Emissions Summary

*Hydrogen Energy, Inc*
*HECA Project*

*6/30/2009*

| Pollutant | Total Annual (ton/yr) | CTG/HRSG Maximum (1) (ton/yr) | Auxiliary CTG (ton/yr) | Cooling Towers (2) (ton/yr) | Auxiliary Boiler (ton/yr) | Emergency Generators (3) (ton/yr) | Fire Water Pump (ton/yr) | Gasification Flare (ton/yr) | SRU Flare (ton/yr) | Rectisol Flare (ton/yr) | Tg Thermal Oxidizer (ton/yr) | $CO_2$ Vent (ton/yr) | Gasifier Warming (ton/yr) | Feedstock (4) (ton/yr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $NO_X$ | 203.8 | 167.2 | 17.4 | -- | 1.7 | 0.2 | 0.1 | 4.3 | 0.2 | 0.2 | 10.9 | -- | 1.8 | -- |
| CO | 350.3 | 150.2 | 27.6 | -- | 5.8 | 0.1 | 0.2 | 48.8 | 0.1 | 0.1 | 9.1 | 106.9 | 1.5 | -- |
| VOC | 40.7 | 32.5 | 4.6 | -- | 0.6 | 0.03 | 0.01 | 0.003 | 0.002 | 0.002 | 0.3 | 2.4 | 0.1 | -- |
| $SO_2$ | 42.2 | 29.2 | 3.8 | -- | 0.3 | 0.001 | 0.0003 | 0.004 | 0.055 | 0.003 | 8.8 | -- | 0.03 | -- |
| $PM_{10}$ | 141.1 | 99.7 | 12.3 | 24.1 | 0.8 | 0.01 | 0.001 | 0.007 | 0.004 | 0.004 | 0.4 | -- | 0.1 | 3.6 |
| $PM_{2.5}$ (5) | 128.9 | 99.7 | 12.3 | 14.5 | 0.8 | 0.01 | 0.001 | 0.007 | 0.004 | 0.004 | 0.4 | -- | 0.1 | 1.0 |
| $NH_3$ | 100.0 | 75.9 | 24.1 | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| $H_2S$ | 1.3 | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 1.3 | -- | -- |
| $CO_2e$ (6) | 383,317 | 5,290 | 198,200 | -- | 16,466 | 146 | 29 | 6,348 | 176 | 139 | 4,797 | 150,011 | 1,716 | -- |

(1) Total annual HRSG emissions represents the maximum emissions rate from a composite firing scenario (all thee fuels)
(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)

## CTG/HRSG Stack - Comparison of all Firing Scenarios — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

**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) |
|---|---|---|---|---|
| $NO_X$ | 148.0 | 167.2 | 162.9 | 167.2 |
| CO | 138.9 | 103.5 | 150.2 | 150.2 |
| VOC | 30.0 | 19.0 | 32.5 | 32.5 |
| $SO_2$ | 20.0 | 28.4 | 29.2 | 29.2 |
| $PM_{10} = PM_{2.5}$ | 74.9 | 99.7 | 99.7 | 99.7 |
| $NH_3$ | 67.1 | 75.9 | 73.9 | 75.9 |

| 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 |
| $SO_2$ | 0.6 | 0.86 | 0.93 | 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) |
|---|---|---|---|---|
| $SO_2$ | 0.6 | 0.86 | 0.93 | 0.9 |

## CTG/HRSG Stack - Comparison of all Firing Scenarios — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

**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 | 164.9 | 164.8 | 164.9 | 164.9 |

**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) |
|---|---|---|---|---|
| $SO_2$ | 0.6 | 0.86 | 0.93 | 0.9 |
| $PM_{10} = PM_{2.5}$ | 2.4 | 3.0 | 3.0 | 3.0 |

**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 | 4.7 | 4.8 |
| CO | 4.0 | 3.0 | 4.3 | 4.3 |
| VOC | 0.9 | 0.5 | 0.9 | 0.9 |
| $SO_2$ | 0.6 | 0.82 | 0.84 | 0.8 |
| $PM_{10} = PM_{2.5}$ | 2.2 | 2.9 | 2.9 | 2.9 |

## CTG/HRSG Stack - Natural Gas — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

**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 | 36.3 | 29.0 | 24.8 | 20.8 | 35.1 | 27.0 | 23.1 | 19.4 | 33.3 | 26.1 | 22.4 | 18.7 |
| CO (@ 5.0 ppm) | lbm/hr | 27.6 | 22.1 | 18.8 | 15.8 | 26.7 | 20.5 | 17.6 | 14.8 | 25.3 | 19.8 | 17.0 | 14.2 |
| VOC (@ 2.0 ppm) | lbm/hr | 6.3 | 5.0 | 4.3 | 3.6 | 6.1 | 4.7 | 4.0 | 3.4 | 5.8 | 4.5 | 3.9 | 3.2 |
| $SO_2$ (@ 12.65 ppmv) | lbm/hr | 5.1 | 4.1 | 3.5 | 3.0 | 4.8 | 3.8 | 3.3 | 2.8 | 4.7 | 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 | 16.7 | 13.4 | 11.4 | 9.6 | 16.2 | 12.5 | 10.7 | 9.0 | 15.4 | 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 |
| $PM_{10} = PM_{2.5}$ | 21.3 | 64.0 | $PM_{10} = PM_{2.5}$ | 23.0 | 23.0 | $PM_{10} = PM_{2.5}$ | 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 $SO_2$ 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 | $NO_X$ | 296,044.0 | 148.0 | 4.3 |
| Total Number of Hot Starts | 10.0 | CO | 277,817.2 | 138.9 | 4.0 |
| Hot Start Duration (hr) | 1.0 | VOC | 59,906.8 | 30.0 | 0.9 |
| Total Number of Shutdowns | 20.0 | $SO_2$ | 40,045.4 | 20.0 | 0.6 |
| Shutdown Duration (hr) | 0.5 | $PM_{10} = PM_{2.5}$ | 149,866.0 | 74.9 | 2.2 |
| Duct Burner Operation (hr) | 8,272.0 | $NH_3$ | 134,158.6 | 67.1 | 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/yr/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 | | $NO_X$ | 74,011.0 | 37.0 |
| **Total Number of Hot Starts** | 2.5 | | CO | 69,454.3 | 34.7 |
| **Hot Start Duration (hr)** | 1.0 | | VOC | 14,976.7 | 7.5 |
| **Total Number of Shutdowns** | 5.0 | | $SO_2$ | 10,011.4 | 5.0 |
| **Shutdown Duration (hr)** | 0.5 | | $PM_{10} = PM_{2.5}$ | 37,466.5 | 18.7 |
| **Duct Burner Operation (hr)** | 2,068.0 | | $NH_3$ | 33,539.7 | 16.8 |
| **Average Normal Operation (hr)** | 0.0 | | | | |

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

**Third Quarter Emissions (Jul, Aug, Sep)**

| | | | Pollutant | Turbine Emissions lb/yr/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 | | $NO_X$ | 74,011.0 | 37.0 |
| **Total Number of Hot Starts** | 2.5 | | CO | 69,454.3 | 34.7 |
| **Hot Start Duration (hr)** | 1.0 | | VOC | 14,976.7 | 7.5 |
| **Total Number of Shutdowns** | 5.0 | | $SO_2$ | 10,011.4 | 5.0 |
| **Shutdown Duration (hr)** | 0.5 | | $PM_{10} = PM_{2.5}$ | 37,466.5 | 18.7 |
| **Duct Burner Operation (hr)** | 2,068.0 | | $NH_3$ | 33,539.7 | 16.8 |
| **Average Normal Operation (hr)** | 0.0 | | | | |

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

**Second Quarter Emissions (Apr, May, Jun)**

| | | | Pollutant | Turbine Emissions lb/yr/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 | | $NO_X$ | 74,011.0 | 37.0 |
| **Total Number of Hot Starts** | 2.5 | | CO | 69,454.3 | 34.7 |
| **Hot Start Duration (hr)** | 1.0 | | VOC | 14,976.7 | 7.5 |
| **Total Number of Shutdowns** | 5.0 | | $SO_2$ | 10,011.4 | 5.0 |
| **Shutdown Duration (hr)** | 0.5 | | $PM_{10} = PM_{2.5}$ | 37,466.5 | 18.7 |
| **Duct Burner Operation (hr)** | 2,068.0 | | $NH_3$ | 33,539.7 | 16.8 |
| **Average Normal Operation (hr)** | 0.0 | | | | |

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

**Fourth Quarter Emissions (Oct, Nov, Dec)**

| | | | Pollutant | Turbine Emissions lb/yr/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 | | $NO_X$ | 74,011.0 | 37.0 |
| **Total Number of Hot Starts** | 2.5 | | CO | 69,454.3 | 34.7 |
| **Hot Start Duration (hr)** | 1.0 | | VOC | 14,976.7 | 7.5 |
| **Total Number of Shutdowns** | 5.0 | | $SO_2$ | 10,011.4 | 5.0 |
| **Shutdown Duration (hr)** | 0.5 | | $PM_{10} = PM_{2.5}$ | 37,466.5 | 18.7 |
| **Duct Burner Operation (hr)** | 2,068.0 | | $NH_3$ | 33,539.7 | 16.8 |
| **Average Normal Operation (hr)** | 0.0 | | | | |

**Assumptions:**
Quarterly normal operational emissions are calculated using yearly average- 65℉, at 100 % load.
Duct burner emissions are calculated using yearly average- 65℉, 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 |
| $SO_2$ | 5.1 | 0.6 |

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

**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 | 5.1 | 15.3 | contribution over 3 hr from normal operation |

| | | |
|---|---|---|
| **$SO_2$ worst-case 3 hr emissions per turbine** | 15.3 | lb/3 hr |
| **$SO_2$ worst-case 1 hr emissions per turbine** | 5.1 | lb/hr |
| **$SO_2$ modeling worst-case emissions per turbine** | 0.6 | 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 $SO_2$ emissions

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**Modeling Worst-Case 8 hr Emissions per Turbine**

| | hr | emission rate lb/hr | Emissions lb/CT | |
|---|---|---|---|---|
| **Total Hours of Operation** | 8.0 | | | |
| **Startup Duration (cold start)** | 6.0 | | 10,078.0 | contribution over 8 hr from start up |
| **Shutdown Duration** | 1.5 | | 378.0 | contribution over 8 hr from shut down |
| **Hours of Normal Operation (burning natural gas)** | 0.5 | 27.6 | 13.8 | contribution over 8 hr from normal operation |
| | | | | |
| **CO worst-case 8 hr emissions per turbine** | 10,469.8 | lb/8 hr | | |
| **CO worst-case 1 hr emissions per turbine** | 1,308.7 | lb/hr | | |
| **CO modeling worst-case emissions per turbine** | 164.9 | 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 : 2
Worst-case 8 hr emissions assumes a total shut down of : 3

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

| | |
|---|---|
| **$SO_2$ (lb/day/CT)** | 122.4 |
| **$SO_2$ (g/s/CT) (burning natural gas)** | 0.6 |
| | |
| **$PM_{10} = PM_{2.5}$ (lb/day/CT)** | |
| **$PM_{10} = PM_{2.5}$ (g/s/CT) (burning natural gas)** | |

**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 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/start | Worst-Case Daily Emissions lb/day/CT | Modeling Worst-Case 24 Hr Emission g/s/CT |
|---|---|---|---|---|---|---|---|---|
| Nox ( 1 COLD start up and I shut down) | 3.0 | 272.0 | 0.5 | 62.0 | 17.5 | 36.3 | 1,426.4 | 7.5 |
| Nox ( 2 HOT start ups and 2 shut downs) | 2.0 | 167.0 | 1.0 | 62.0 | | | | |
| CO | 12.0 | 5,039.0 | 2.0 | 126.0 | 10.0 | 27.6 | 20,935.8 | |
| VOC | 12.0 | 800.0 | 2.0 | 21.0 | 10.0 | 6.3 | 3,347.0 | |
| $SO_2$ | | | | | | | | |
| $PM_{10} = PM_{2.5}$ | 12.0 | 64.0 | 2.0 | 5.0 | 10.0 | 18.0 | 456.0 | 2.4 |

**Assumptions:**
For CO, VOC, and PM -- emissions are calculated assuming:
Worst-case daily emissions assumes a total COLD start up of : 4
Worst-case daily emissions assumes a total shut down of : 4
Remainder of time is spent in normal operation at winter minimum - 20℉; 100% load

For CALPUFF modeling purposes, NOx emissions are calculated assuming:
Worst-case daily emissions assumes a total COLD start up of : 1 and a total HOT start up of: 2
Worst-case daily emissions assumes a total shut down of : 3
Remainder of time is spent in normal operation at winter minimum - 20℉; 100% load

See above calculation for worst-case daily $SO_2$:calculated as 24 hrs of normal operation at max emissions rate

## CTG/HRSG Stack - SynGas — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

**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 | | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 | 24.0 |
| $NH_3$ (@ 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 |
| $PM_{10} = PM_{2.5}$ | 21.3 | 64.0 | $PM_{10} = PM_{2.5}$ | 23.0 | 23.0 | $PM_{10} = PM_{2.5}$ | 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 $SO_2$ 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 | Emissions | Emissions |
|---|---|---|---|---|---|---|
| Total Hours of Operation | 8,322.0 | | | | | |
| Total Number of Cold Starts | 10.0 | | | lb/yr/CT | ton/yr/CT | g/sec/CT |
| Cold Start Duration (hr) | 3.0 | | $NO_X$ | 334,353.0 | 167.2 | 4.8 |
| Total Number of Hot Starts | 10.0 | | CO | 206,919.2 | 103.5 | 3.0 |
| Hot Start Duration (hr) | 1.0 | | VOC | 37,984.6 | 19.0 | 0.5 |
| Total Number of Shutdowns | 20.0 | | $SO_2$ | 56,713.0 | 28.4 | 0.8 |
| Shutdown Duration (hr) | 0.5 | | $PM_{10} = PM_{2.5}$ | 199,498.0 | 99.7 | 2.9 |
| Duct Burner Operation (hr) | 8,272.0 | | $NH_3$ | 151,855.7 | 75.9 | 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 |

## CTG/HRSG Stack - SynGas — Emissions Summary

*Hydrogen Energy, Inc*
*HECA Project*

*6/30/2009*

### First Quarter Emissions (Jan, Feb, Mar)

| | | Pollutant | Turbine Emissions lb/yr/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 | $NO_X$ | 83,588.3 | 41.8 |
| **Total Number of Hot Starts** | 2.5 | CO | 51,729.8 | 25.9 |
| **Hot Start Duration (hr)** | 1.0 | VOC | 9,496.2 | 4.7 |
| **Total Number of Shutdowns** | 5.0 | $SO_2$ | 14,178.3 | 7.1 |
| **Shutdown Duration (hr)** | 0.5 | $PM_{10} = PM_{2.5}$ | 49,874.5 | 24.9 |
| **Duct Burner Operation (hr)** | 2,068.0 | $NH_3$ | 37,963.9 | 19.0 |
| **Average Normal Operation (hr)** | 0.0 | | | |

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

### Second Quarter Emissions (Apr, May, Jun)

| | | Pollutant | Turbine Emissions lb/yr/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 | $NO_X$ | 83,588.3 | 41.8 |
| **Total Number of Hot Starts** | 2.5 | CO | 51,729.8 | 25.9 |
| **Hot Start Duration (hr)** | 1.0 | VOC | 9,496.2 | 4.7 |
| **Total Number of Shutdowns** | 5.0 | $SO_2$ | 14,178.3 | 7.1 |
| **Shutdown Duration (hr)** | 0.5 | $PM_{10} = PM_{2.5}$ | 49,874.5 | 24.9 |
| **Duct Burner Operation (hr)** | 2,068.0 | $NH_3$ | 37,963.9 | 19.0 |
| **Average Normal Operation (hr)** | 0.0 | | | |

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

### Third Quarter Emissions (Jul, Aug, Sep)

| | | Pollutant | Turbine Emissions lb/yr/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 | $NO_X$ | 83,588.3 | 41.8 |
| **Total Number of Hot Starts** | 2.5 | CO | 51,729.8 | 25.9 |
| **Hot Start Duration (hr)** | 1.0 | VOC | 9,496.2 | 4.7 |
| **Total Number of Shutdowns** | 5.0 | $SO_2$ | 14,178.3 | 7.1 |
| **Shutdown Duration (hr)** | 0.5 | $PM_{10} = PM_{2.5}$ | 49,874.5 | 24.9 |
| **Duct Burner Operation (hr)** | 2,068.0 | $NH_3$ | 37,963.9 | 19.0 |
| **Average Normal Operation (hr)** | 0.0 | | | |

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

### Fourth Quarter Emissions (Oct, Nov, Dec)

| | | Pollutant | Turbine Emissions lb/yr/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 | $NO_X$ | 83,588.3 | 41.8 |
| **Total Number of Hot Starts** | 2.5 | CO | 51,729.8 | 25.9 |
| **Hot Start Duration (hr)** | 1.0 | VOC | 9,496.2 | 4.7 |
| **Total Number of Shutdowns** | 5.0 | $SO_2$ | 14,178.3 | 7.1 |
| **Shutdown Duration (hr)** | 0.5 | $PM_{10} = PM_{2.5}$ | 49,874.5 | 24.9 |
| **Duct Burner Operation (hr)** | 2,068.0 | $NH_3$ | 37,963.9 | 19.0 |
| **Average Normal Operation (hr)** | 0.0 | | | |

**Assumptions:**
Quarterly normal operational emissions are calculated using yearly average- 65℉, at 100 % load.
Duct burner emissions are calculated using yearly average- 65℉, 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) $SO_2$ emissions.

### 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.

*Hydrogen Energy, Inc*
*HECA Project*
*6/30/2009*

**Modeling Worst-Case 8 hr Emissions per Turbine**

| | hr | emission rate lb/hr | Emissions lb/CT | |
|---|---|---|---|---|
| **Total Hours of Operation** | 8.0 | | | |
| **Startup Duration** | 6.0 | | 10,078.0 | contribution over 8 hr from start up |
| **Shutdown Duration** | 1.5 | | 378.0 | contribution over 8 hr from shut down |
| **Hours of Normal Operation (burning syngas)** | 0.5 | 18.1 | 9.1 | contribution over 8 hr from normal operation |
| **CO worst-case 8 hr emissions per turbine** | 10,465.1 | lb/8 hr | | |
| **CO worst-case 1 hr emissions per turbine** | 1,308.1 | lb/hr | | |
| **CO modeling worst-case emissions per turbine** | 164.8 | 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 : 2
Worst-case 8 hr emissions assumes a total shut down of : 3

**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)** | 576.0 |
| **$PM_{10} = PM_{2.5}$ (g/s/CT) (burning syngas)** | 3.0 |

**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 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/start | Worst-Case Daily Emissions lb/day/CT | Modeling Worst-Case 24 Hr Emission g/s/CT |
|---|---|---|---|---|---|---|---|---|
| NOx | 12.0 | 272.0 | 2.0 | 62.0 | 10.0 | 39.7 | 1,733.4 | |
| CO | 12.0 | 5,039.0 | 2.0 | 126.0 | 10.0 | 18.1 | 20,841.4 | |
| VOC | 12.0 | 800.0 | 2.0 | 21.0 | 10.0 | 3.5 | 3,318.6 | |
| $SO_2$ | | | | | | | | |
| $PM_{10} = PM_{2.5}$ | | | | | | | | |

**Assumptions:**
For NOx, CO, and VOC -- emissions are calculated assuming:
Worst-case daily emissions assumes a total start up of : 4
Worst-case daily emissions assumes a total shut down of : 4
Remainder of time is spent in normal operation at max emission rate
See above calculation for worst-case daily $SO_2$ and PM: calculated as 24 hrs of normal operationat max emissions rate

## CTG/HRSG Stack - Co Firing

*Hydrogen Energy, Inc*
*HECA Project*

**CTG Operating Parameters**

| Ambient Temperature | UNITS | Winter Minimum - 20℉ | | | | | |
|---|---|---|---|---|---|---|---|
| CTG Load Level | Percent Load (%) | 100% | 100% | 80% | 60% | 100% | |
| Evap Cooling Status | off / on | N/A | N/A | N/A | N/A | N/A | |
| Duct Burner Status | off / on | On | Off | Off | Off | On | |

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

| | UNITS | Winter Minimum - 20℉ | | | | | |
|---|---|---|---|---|---|---|---|
| $NO_x$ (@ 4.0 ppm) | lbm/hr | 41.3 | 34.0 | | | 38.7 | |
| CO (@ 5.0 ppm) | lbm/hr | 31.4 | 25.9 | | | 29.4 | |
| VOC (@ 2.0 ppm) | lbm/hr | 7.2 | 5.9 | | | 6.7 | |
| $SO_2$ (@ 6.7 ppmv, average) (12.65 ppm duct firing) | lbm/hr | 7.4 | 5.2 | | | 7.0 | |
| $PM_{10} = PM_{2.5}$ | lbm/hr | 24.0 | 24.0 | | | 24.0 | |
| $NH_3$ (@ 5.0 ppm slip) | lbm/hr | 19.1 | 15.7 | | | 17.9 | |

All turbine operating parameters and emissions data provided by FLUOR based on expected operating parameters. 5.0659
Co-firing emissions are controlled at the same amount as natural gas.

**Startup / Shutdown Emissions from Turbine (1CT)**

| Cold Startup | | | Hot Startup | | | | |
|---|---|---|---|---|---|---|---|
| 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) | |
| $NO_X$ | 90.7 | 272.0 | NOx | 167.0 | 167.0 | NOx | |
| CO | 1,679.7 | 5,039.0 | CO | 394.0 | 394.0 | CO | |
| VOC | 266.7 | 800.0 | VOC | 98.0 | 98.0 | VOC | |
| $SO_2$ (@ 12.65 ppmv) | 5.1 | 15.3 | SO2 | 5.1 | 5.1 | SO2 | |
| $PM_{10} = PM_{2.5}$ | 21.3 | 64.0 | $PM_{10} = PM_{2.5}$ | 23.0 | 23.0 | $PM_{10} = PM_{2.5}$ | |

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 $SO_2$ 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 | | $NO_X$ | 325,712.3 | 162.9 | 4.7 |
| Total Number of Hot Starts | 10.0 | | CO | 300,390.9 | 150.2 | 4.3 |
| Hot Start Duration (hr) | 1.0 | | VOC | 65,066.5 | 32.5 | 0.9 |
| Total Number of Shutdowns | 20.0 | | $SO_2$ | 58,357.9 | 29.2 | 0.8 |
| Shutdown Duration (hr) | 0.5 | | $PM_{10} = PM_{2.5}$ | 199,498.0 | 99.7 | 2.9 |
| Duct Burner Operation (hr) | 8,272.0 | | $NH_3$ | 147,864.1 | 73.9 | 2.1 |
| Average Normal Operation (hr) | 0.0 | | | | | |

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

## CTG/HRSG Stack - Co Firing

*Hydrogen Energy, Inc*
*HECA Project*

**First Quarter Emissions (Jan, Feb, Mar)**

| | | Pollutant | Turbine Emissions lb/yr/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 | $NO_X$ | 81,428.1 | 40.7 |
| **Total Number of Hot Starts** | 2.5 | CO | 75,097.7 | 37.5 |
| **Hot Start Duration (hr)** | 1.0 | VOC | 16,266.6 | 8.1 |
| **Total Number of Shutdowns** | 5.0 | $SO_2$ | 14,589.5 | 7.3 |
| **Shutdown Duration (hr)** | 0.5 | $PM_{10} = PM_{2.5}$ | 49,874.5 | 24.9 |
| **Duct Burner Operation (hr)** | 2,068.0 | $NH_3$ | 36,966.0 | 18.5 |
| **Average Normal Operation (hr)** | 0.0 | | | |

**Assumptions:**
Quarterly 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.

**Second Quarter Emissions (Apr, May, Jun)**

| | | Pollutant | Turbine Emissions lb/yr/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 | $NO_X$ | 81,428.1 | 40.7 |
| **Total Number of Hot Starts** | 2.5 | CO | 75,097.7 | 37.5 |
| **Hot Start Duration (hr)** | 1.0 | VOC | 16,266.6 | 8.1 |
| **Total Number of Shutdowns** | 5.0 | $SO_2$ | 14,589.5 | 7.3 |
| **Shutdown Duration (hr)** | 0.5 | $PM_{10} = PM_{2.5}$ | 49,874.5 | 24.9 |
| **Duct Burner Operation (hr)** | 2,068.0 | $NH_3$ | 36,966.0 | 18.5 |
| **Average Normal Operation (hr)** | 0.0 | | | |

**Assumptions:**
Quarterly 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.

**Third Qua**

| |
|---|
| **Total Hou** |
| **Total Nur** |
| **Cold Star** |
| **Total Nur** |
| **Hot Start** |
| **Total Nur** |
| **Shutdow** |
| **Duct Bur** |
| **Average I** |

**Assumptior**
Quarterly no
Duct burner

**Fourth Qu**

| |
|---|
| **Total Hou** |
| **Total Nur** |
| **Cold Star** |
| **Total Nur** |
| **Hot Start** |
| **Total Nur** |
| **Shutdow** |
| **Duct Bur** |
| **Average I** |

**Assumptior**
Quarterly no
Duct burner

**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 |
| $SO_2$ | 7.4 | 0.93 |

**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) $SO_2$ emissions.

**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 | 7.4 | 22.1 | contribution over 3 hr from normal operation |

| | | |
|---|---|---|
| **$SO_2$ worst-case 3 hr emissions per turbine** | 22.1 | lb/3 hr |
| **$SO_2$ worst-case 1 hr emissions per turbine** | 7.4 | 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 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.

## CTG/HRSG Stack - Co Firing

*Hydrogen Energy, Inc*
*HECA Project*

**Modeling Worst-Case 8 hr Emissions per Turbine**

| | hr | emission rate lb/hr | Emissions lb/CT | |
|---|---|---|---|---|
| **Total Hours of Operation** | 8.0 | | | |
| **Startup Duration** | 6.0 | | 10,078.0 | contribution over 8 hr from start up |
| **Shutdown Duration** | 1.5 | | 378.0 | contribution over 8 hr from shut down |
| **Hours of Normal Operation (co firing)** | 0.5 | 31.4 | 15.7 | contribution over 8 hr from normal operation |
| | | | | |
| **CO worst-case 8 hr emissions per turbine** | 10,471.7 | lb/8 hr | | |
| **CO worst-case 1 hr emissions per turbine** | 1,309.0 | lb/hr | | |
| **CO modeling worst-case emissions per turbine** | 164.9 | 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 : 2
Worst-case 8 hr emissions assumes a total shut down of : 3

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

| | |
|---|---|
| **$SO_2$ (lb/day/CT)** | 177.2 |
| **SO2 (g/s/CT) (co firing)** | 0.9 |
| | |
| **$PM_{10} = PM_{2.5}$ (lb/day/CT)** | 576.0 |
| **$PM_{10} = PM_{2.5}$ (g/s/CT) (cofiring)** | 3.0 |

**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 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/start | Wors |
|---|---|---|---|---|---|---|---|
| NOx | 12.0 | 272.0 | 2.0 | 62.0 | 10.0 | 41.3 | |
| CO | 12.0 | 5,039.0 | 2.0 | 126.0 | 10.0 | 31.4 | |
| VOC | 12.0 | 800.0 | 2.0 | 21.0 | 10.0 | 7.2 | |
| $SO_2$ | | | | | | | |
| $PM_{10} = PM_{2.5}$ | | | | | | | |

**Assumptions:**
For NOx, CO, and VOC -- emissions are calculated assuming:
Worst-case daily emissions assumes a total start up of : 4
Worst-case daily emissions assumes a total shut down of : 4
Remainder of time is spent in normal operation at max emission rate
See above calculation for worst-case daily $SO_2$ and PM: calculated as 24 hrs of normal operationat max emissions rate

## Auxiliary CTG

*Hydrogen Energy, Inc*
*HECA Project*

**CTG Operating Parameters**

| Ambient Temperature | UNITS | Winter Minimum - 20℉ | | | | | |
|---|---|---|---|---|---|---|---|
| CTG Load Level | Percent Load (%) | 100% | 100% | 75% | 50% | 100% | |
| Evap Cooling Status | off / on | Off | Off | Off | Off | On | |

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

| | UNITS | Winter Minimum - 20℉ | | | | | |
|---|---|---|---|---|---|---|---|
| $NO_x$ (@ 2.5 ppm) | lbm/hr | | 7.9 | 6.4 | 4.7 | 8.1 | |
| CO (@ 6.0 ppm) | lbm/hr | | 11.5 | 9.3 | 6.9 | 11.9 | |
| VOC (@ 2.0 ppm) | lbm/hr | | 2.2 | 1.8 | 1.3 | 2.3 | |
| $SO_2$ (@ 12.65 ppmv) | lbm/hr | | 1.8 | 1.4 | 1.1 | 1.9 | |
| $PM_{10} = PM_{2.5}$ | lbm/hr | | 6.0 | 6.0 | 6.0 | 6.0 | |
| $NH_3$ (@ 10.0 ppm slip) | lbm/hr | | 11.6 | 9.5 | 7.0 | 12.0 | |

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 | | | | |
|---|---|---|---|---|---|---|---|
| 10.0 (min. in cold startup) | Max 1-hr. (lb/hr) | Total (lb/10min) | 0 (min. in hot startup) | Max 1-hr. (lb/hr) | Total (lb/60min) | 10.3 (min. in shutdown) | |
| $NO_X$ | 9.0 | 3.0 | NOx | | | NOx | |
| CO | 30.6 | 10.2 | CO | | | CO | |
| VOC | 0.5 | 0.2 | VOC | | | VOC | |
| $SO_2$ (@ 12.65 ppmv) | 1.9 | 0.3 | $SO_2$ | | | $SO_2$ | |
| $PM_{10} = PM_{2.5}$ | 6.0 | 1.0 | $PM_{10} = PM_{2.5}$ | | | $PM_{10} = PM_{2.5}$ | |

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

NOx, CO, and VOC startup and shutdown emissions (max 1-hr) assume 3 startup and 3 shut down

Startup and shutdown SO2 and PM10 emissions will always be lower than normal operational emissions. Startup and shutdown emissions are assumed equal to normal operations max emission rate, with evap cooling.

**Average Annual Emissions and Modeling Rates**

| | |
|---|---|
| Total Hours of Operation | 4,110 |
| Total Number of Cold Starts | 325.0 |
| Cold Start Duration (hr) | 0.2 |
| Total Number of Hot Starts | 0.0 |
| Hot Start Duration (hr) | 0.0 |
| Total Number of Shutdowns | 325.0 |
| Shutdown Duration (hr) | 0.2 |
| Evaporative Cooling Operation (hr) | 4,000 |
| Average Normal Operation (hr) | 0.0 |

| Pollutant | Turbine Emissions lb/yr/CT | Emissions ton/yr/CT | Emissions g/sec/CT |
|---|---|---|---|
| $NO_X$ | 34,840.6 | 17.4 | 0.5 |
| CO | 55,179.1 | 27.6 | 0.8 |
| VOC | 9,182.0 | 4.6 | 0.1 |
| $SO_2$ | 7,644.4 | 3.8 | 0.1 |
| $PM_{10} = PM_{2.5}$ | 24,660.0 | 12.3 | 0.4 |
| $NH_3$ | 48,140.5 | 24.1 | 0.7 |

**Assumptions:**

Average annual operational emissions are calculated using yearly average- 65℉, at 100 % load, with evaporative cool ing.

## Auxiliary CTG

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*HECA Project*

**First Quarter Emissions (Jan, Feb, Mar)**

| | | | Pollutant | Turbine Emissions lb/yr/CT | Emissions ton/yr/CT |
|---|---|---|---|---|---|
| **Total Hours of Operation** | 1,027.5 | | | | |
| **Total Number of Cold Starts** | 81.3 | | | | |
| **Cold Start Duration (hr)** | 0.2 | | $NO_X$ | 8,710.2 | 4.4 |
| **Total Number of Hot Starts** | 0.0 | | CO | 13,794.8 | 6.9 |
| **Hot Start Duration (hr)** | 0.0 | | VOC | 2,295.5 | 1.1 |
| **Total Number of Shutdowns** | 81.3 | | $SO_2$ | 1,911.1 | 1.0 |
| **Shutdown Duration (hr)** | 0.2 | | $PM_{10} = PM_{2.5}$ | 6,165.0 | 3.1 |
| **Evaporative Cooling Operation (hr)** | 1,000.0 | | $NH_3$ | 12,035.1 | 6.0 |
| **Average Normal Operation (hr)** | 0.0 | | | | |

**Assumptions:**
Quarterly operational emissions are calculated using yearly average- 65℉, at 100 % load, with evaporative cooling.

**Second Quarter Emissions (Apr, May, Jun)**

| | | | Pollutant | Turbine Emissions lb/yr/CT | Emissions ton/yr/CT |
|---|---|---|---|---|---|
| **Total Hours of Operation** | 1,027.5 | | | | |
| **Total Number of Cold Starts** | 81.3 | | | | |
| **Cold Start Duration (hr)** | 0.2 | | $NO_X$ | 8,710.2 | 4.4 |
| **Total Number of Hot Starts** | 0.0 | | CO | 13,794.8 | 6.9 |
| **Hot Start Duration (hr)** | 0.0 | | VOC | 2,295.5 | 1.1 |
| **Total Number of Shutdowns** | 81.3 | | $SO_2$ | 1,911.1 | 1.0 |
| **Shutdown Duration (hr)** | 0.2 | | $PM_{10} = PM_{2.5}$ | 6,165.0 | 3.1 |
| **Evaporative Cooling Operation (hr)** | 1,000.0 | | $NH_3$ | 12,035.1 | 6.0 |
| **Average Normal Operation (hr)** | 0.0 | | | | |

**Assumptions:**
Quarterly operational emissions are calculated using yearly average- 65℉, at 100 % load, with evaporative cooling.

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**Modeling Worst-Case 1 hr Emissions per Turbine**

| Pollutant | lb/hr/CT | g/sec/CT |
|---|---|---|
| NOx | 20.7 | 2.6 |
| CO | 69.0 | 8.7 |
| $SO_2$ | 1.9 | 0.2 |

**Assumptions:**
Startup emissions represent worst case hr for NOx and CO.
NOx, and CO worst case 1 hr assume the contribution over 1 hr from 3 startup and 3 shut down
Calculation assumes that startup and shutdown $SO_2$ emissions will always be lower than normal operational $SO_2$ emissions.

**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** | 3.0 | 1.9 | 5.6 | contribution over 3 hr from normal operation |

| | | |
|---|---|---|
| **$SO_2$ worst-case 3 hr emissions per turbine** | 5.6 | lb/3 hr |
| **$SO_2$ worst-case 1 hr emissions per turbine** | 1.9 | lb/hr |
| **$SO_2$ modeling worst-case emissions per turbine** | 0.2 | 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 $SO_2$ emissions

## Auxiliary CTG

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*HECA Project*

**Modeling Worst-Case 8 hr Emissions per Turbine**

| | hr | emission rate lb/hr | Emissions lb/CT | |
|---|---|---|---|---|
| **Total Hours of Operation** | 8.0 | | | |
| **Startup Duration** | 0.7 | | 40.8 | contribution over 8 hr from start up |
| **Shutdown Duration** | 0.7 | | 52.8 | contribution over 8 hr from shut down |
| **Hours of Normal Operation** | 6.6 | 11.9 | 79.0 | contribution over 8 hr from normal operation |
| | | | | |
| **CO worst-case 8 hr emissions per turbine** | 172.6 | lb/8 hr | | |
| **CO worst-case 1 hr emissions per turbine** | 21.6 | lb/hr | | |
| **CO modeling worst-case emissions per turbine** | 2.7 | g/sec | | |

**Assumptions:**
Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Normal operation assumes annual average - 65°F; 100% load, with evap cooling.
Worst-case 8 hr emissions assumes a total start up of : 4
Worst-case 8 hr emissions assumes a total shut down of : 4

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

| | |
|---|---|
| **$SO_2$ (lb/day/CT)** | 44.6 |
| **$SO_2$ (g/s/CT)** | 0.2 |
| | |
| **$PM_{10} = PM_{2.5}$ (lb/day/CT)** | 144.0 |
| **$PM_{10} = PM_{2.5}$ (g/s/CT)** | 0.8 |

**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 maximum emission rate
For PM 24 hrs of normal operation at maximum emission rate

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

| Pollutant | Time in 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/start |
|---|---|---|---|---|---|---|
| NOx | 0.7 | 3.0 | 0.7 | 4.0 | 22.6 | 8.1 |
| CO | 0.7 | 10.2 | 0.7 | 13.2 | 22.6 | 11.9 |
| VOC | 0.7 | 0.2 | 0.7 | 0.2 | 22.6 | 2.3 |
| $SO_2$ | | | | | | |
| $PM_{10} = PM_{2.5}$ | | | | | | |

**Assumptions:**
For NOx, CO, and VOC -- emissions are calculated assuming:
Worst-case daily emissions assumes a total start up of : 4
Worst-case daily emissions assumes a total shut down of : 4
Remainder of time is spent in normal operation at max emission rate
See above calculation for worst-case daily $SO_2$ and PM: calculated as 24 hrs of normal operationat max emission rate

*Hydrogen Energy, Inc* *6/30/2009*
*HECA Project*

**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, 9 ppmvd (3% O2)) | 0.011 | 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 |

**Auxiliary Boiler Pollutant Emission Rates**

| | Auxiliary Boiler Emissions | | | | |
|---|---|---|---|---|---|
| **Pollutant** | **lb/hr** | **lb/day** | **lb/yr** | **ton/qtr** | **ton/yr** |
| NOx | 1.56 | 37.49 | 3,420.78 | 0.43 | 1.7 |
| 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 |

## Auxiliary Boiler — Emissions Summary

*Hydrogen Energy, Inc*
*HECA Project*

*6/30/2009*

### Modeling Worst-Case 1 hr Emissions

| | |
|---|---|
| NOx (g/sec) | 0.2 |
| 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 |

### 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) | 0.05 |
| 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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*HECA Project*

**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** |
| 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 |
| VOC (lb/MMBtu, HHV) | 0.0013 |
| $PM_{10} = PM_{2.5}$ (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 |
| $SO_2$ | 0.001 | 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 and Shutdown

| | | |
|---|---|---|
| **Total Flare SU/SD Operation** | 115,500 | MMBtu/yr |
| **Wet Unshifted Gas Heat Rate** | 900 | MMBtu/hr |
| **Dry Shifted Gas Heat Rate** | 768 | MMBtu/hr |
| **Approximate Operating Hours (wet)** | 96 | hr/yr |
| **Approximate Operating Hours (dry)** | 38 | hr/yr |

**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** | **115,500** | **MMBtu/yr** | (approx 75% unshifted) |

### SU/SD Flare Pollutant Emission Factors

| | |
|---|---|
| NOx (lb/MMBtu, HHV) | 0.07 |
| CO (lb/MMBtu, HHV) (wet) | 1.00 |
| 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 |

### 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/dr** |
| NOx | 63.0 | 53.8 | 75.0% | 25.0% | 60.70 | 1.01 |
| CO | 900.0 | 284.3 | 75.0% | 25.0% | 746.08 | 12.16 |
| VOC | 0 | 0 | 0 | 0 | 0 | 0 |
| $SO_2$ | 0 | 0 | 0 | 0 | 0 | 0 |
| $PM_{10}$ = $PM_{2.5}$ | 0 | 0 | 0 | 0 | 0 | 0 |

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

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**Total Gasification Flare Emissions**

| Pollutant | Emissions Pilot (ton/yr) | SU/SD (ton/yr) | Total (ton/qtr) | Total (ton/yr) |
|---|---|---|---|---|
| NOx | 0.26 | 4.04 | 1.08 | 4.3 |
| CO | 0.18 | 48.65 | 12.21 | 48.8 |
| VOC | 0.003 | 0.00 | 0.001 | 0.003 |
| $SO_2$ | 0.004 | 0.00 | 0.001 | 0.004 |
| $PM_{10}$ = $PM_{2.5}$ | 0.01 | 0.00 | 0.002 | 0.01 |

**Modeling Worst-Case 1 hr Emissions**

| | |
|---|---|
| NOx (g/sec) | 7.9 |
| CO (g/sec) | 113.4 |
| $SO_2$ (g/sec) | 0.0001 |

Only NOx, CO, and $SO_2$ are considered for an average 1-hour Ambient Air Quality Standard.

NOx and CO rates are taken from the SU/SD flaring events

$SO_2$ rate is from pilot operation

**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) | 0.003 |
| $SO_2$ (g/sec) | 0.0001 |

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 pilot operation.

**Modeling Worst-Case 8 hr Emissions**

| | |
|---|---|
| CO (lb/8-hr) | 7,200.00 |
| CO (g/sec) | 113.4 |

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.

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**Modeling Worst-Case 24 Hour Emissions**

| | |
|---|---|
| $SO_2$ (lb/24-hr) | 0.02 |
| $SO_2$ (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 24 hours of pilot operation.

**Modeling Annual Average Emissions**

| | |
|---|---|
| NOx (g/sec) | 0.1 |
| CO (g/sec) | 1.4 |
| VOC (g/sec) | 0.0001 |
| $SO_2$ (g/sec) | 0.0001 |
| $PM_{10}$ = $PM_{2.5}$ (g/sec) | 0.0002 |

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

## SRU Flare  Emis

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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** |
| 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** | 6.0 | hr/yr | approximately | 2 | events |
| Control efficiency of scrubber = | 99.62% | | | | |
| Acid gas lb/hr SO2 = | 4,600 | lb/hr scrubbed SO2= | 17.3 | | |

### 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 | 17.33 |
| $PM_{10} = PM_{2.5}$(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 | 13.0 | 25.9 | 0.00324 | 0.0130 |
| CO | 2.88 | 8.6 | 17.3 | 0.00216 | 0.0086 |
| VOC | 0.05 | 0.1 | 0.3 | 0 | 0.0001 |
| $SO_2$ | 17.41 | 52.2 | 104.4 | 0.01 | 0.0522 |
| $PM_{10} = PM_{2.5}$ | 0.11 | 0.3 | 0.6 | 0 | 0.0003 |

### SRU Flare - Total Annual Emissions

| | Emissions | | | |
|---|---|---|---|---|
| **Pollutant** | **Pilot (ton/yr)** | **SU/SD (ton/yr)** | **Total (ton/qtr)** | **Total (ton/yr)** |
| NOx | 0.16 | 0.0130 | 0.04 | 0.2 |
| CO | 0.11 | 0.0086 | 0.03 | 0.1 |
| VOC | 0.002 | 0.0001 | 0.000 | 0.002 |
| $SO_2$ | 0.003 | 0.05 | 0.014 | 0.1 |
| $PM_{10} = PM_{2.5}$ | 0.004 | 0.0003 | 0.001 | 0.004 |

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**Modeling Worst-Case 1 hr Emissions**

| | |
|---|---|
| NOx (g/sec) | 0.544 |
| CO (g/sec) | 0.363 |
| $SO_2$ (g/sec) | 2.19 |

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) | 52.22 |
| $SO_2$ (g/sec) | 2.19 |

Only $SO_2$ is considered for an average 3-hour Ambient Air Quality Standard.
Pounds per 3-hr assumes aproximately 3 hours (1 event) from SU/SD flaring.

**Modeling Worst-Case 8 hr Emissions**

| | |
|---|---|
| CO (lb/8-hr) | 8.76 |
| CO (g/sec) | 0.138 |

Only CO is considered for an average 8-hour Ambient Air Quality Standard.
Pounds per 8-hr assumes aproximately 3 hours (1 event) from SU/SD flaring and the remainder in pilot operation.

**Modeling Worst-Case 24 Hour Emissions**

| | |
|---|---|
| $SO_2$ (lb/24-hr) | 52.23 |
| $SO_2$ (g/sec) | 0.27 |
| $PM_{10} = PM_{2.5}$ (lb/24-hr) | 0.34 |
| $PM_{10} = PM_{2.5}$ (g/sec) | 0.0018 |

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 3 hours (1 event) from SU/SD flaring and the remainder in pilot operation.

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**Modeling Annual Average Emissions**

| | |
|---|---|
| NOx (g/sec) | 0.005 |
| CO (g/sec) | 0.003 |
| VOC (g/sec) | 0.00005 |
| $SO_2$ (g/sec) | 0.002 |
| $PM_{10}$ = $PM_{2.5}$ (g/sec) | 0.0001 |

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

## Rectisol Flare — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

### 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 |

**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 |

**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.

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Pounds per 3-hr assumes aproximately 3 hours the natural gas pilot emissions.

| Rectisol Flare | Emissions Summary |
|---|---|

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**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 32 hoursof 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

## Tail Gas Thermal Oxidizer — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*

*HECA Project*

**Thermal Oxidizer - Process Vent Disposal Emissions**

| | | |
|---|---|---|
| **Total Hours of Operation** | 8,760 | hr/yr |
| **Thermal Oxidizer Firing Rate** | 10 | MMBtu/hr |

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

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) | 0.0070 |
| $SO_2$ (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 | 21,024.00 | 2.63 | 10.5 |
| CO | 2.00 | 48.00 | 17,520.00 | 2.19 | 8.8 |
| VOC | 0.07 | 1.68 | 613.20 | 0.0767 | 0.3 |
| $SO_2$ | 2.00 | 48.00 | 17,520.00 | 2.1900 | 8.8 |
| $PM_{10} = PM_{2.5}$ | 0.08 | 1.92 | 700.80 | 0.09 | 0.4 |

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

## Tail Gas Thermal Oxidizer — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

### 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) | 0.007 |
| $SO_2$ (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 | 0.07 | 1.68 | 21.00 | 0.003 | 0.011 |
| $SO_2$ | 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 (ton/yr)** | **SU/SD (ton/yr)** | **Total (ton/qtr)** | **Total (ton/yr)** |
| NOx | 10.51 | 0.36 | 2.72 | 10.9 |
| CO | 8.76 | 0.30 | 2.27 | 9.1 |
| VOC | 0.31 | 0.011 | 0.08 | 0.3 |
| $SO_2$ | 8.76 | 0.003 | 2.19 | 8.8 |
| $PM_{10} = PM_{2.5}$ | 0.35 | 0.012 | 0.09 | 0.4 |

## Tail Gas Thermal Oxidizer — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

**Modeling Worst-Case 1 hr Emissions**

| | |
|---|---|
| NOx (g/sec) | 0.6 |
| CO (g/sec) | 0.50 |
| $SO_2$ (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 both process venting and SRU startup.

**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) | 6.06 |
| $SO_2$ (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 both process venting and SRU startup.

**Modeling Worst-Case 8 hr Emissions**

| | |
|---|---|
| CO (lb/8-hr) | 32.00 |
| CO (g/sec) | 0.5 |

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

**Modeling Worst-Case 24 Hour Emissions**

| | |
|---|---|
| $SO_2$ (lb/24-hr) | 48.49 |
| $SO_2$ (g/sec) | 0.3 |
| $PM_{10} = PM_{2.5}$ (lb/24-hr) | 3.84 |
| $PM_{10} = PM_{2.5}$ (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 oxidation from both process venting and SRU startup.

**Modeling Annual Average Emissions**

| | |
|---|---|
| NOx (g/sec) | 0.3 |
| CO (g/sec) | 0.26 |
| VOC (g/sec) | 0.01 |
| $SO_2$ (g/sec) | 0.3 |
| $PM_{10} = PM_{2.5}$ (g/sec) | 0.01 |

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

## Gasifier Warming — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

**Gasifier Warming Emissions - Normal Operation**

| | | |
|---|---|---|
| **Total Hours of Operation** | 1,800 | hr/yr |
| **Gasifier Firing Rate** | 18 | MMBtu/hr |

| Hours per Qtr | | | |
|---|---|---|---|
| **Q1** | **Q2** | **Q3** | **Q4** |
| 450 | 450 | 450 | 450 |

Assuming equal operation in each quarter

**Gasifier Pollutant Emission Factors**

| | |
|---|---|
| NOx (lb/MMBtu, HHV) | 0.11 |
| CO (lb/MMBtu, HHV) | 0.09 |
| VOC (lb/MMBtu, HHV) | 0.007 |
| $SO_2$ (lb/MMBtu, HHV) (12.65 ppm) | 0.002 |
| $PM_{10}$ = $PM_{2.5}$ (lb/MMBtu, HHV) | 0.008 |

**Gasifier Pollutant Emission Rates**

| | Gasifier Emissions | | | | |
|---|---|---|---|---|---|
| **Pollutant** | **lb/hr** | **lb/day** | **lb/yr** | **ton/qtr** | **ton/yr** |
| NOx | 1.98 | 47.52 | 3,564.00 | 0.45 | 1.8 |
| CO | 1.62 | 38.88 | 2,916.00 | 0.36 | 1.5 |
| VOC | 0.13 | 3.02 | 226.80 | 0.03 | 0.1 |
| $SO_2$ | 0.04 | 0.88 | 66.10 | 0.01 | 0.0 |
| $PM_{10}$ = $PM_{2.5}$ | 0.14 | 3.46 | 259.20 | 0.03 | 0.1 |

***Please Note That There Are Three Gassifiers; However, Under Normal Operations, Only One Operates At A Time.***

## Gasifier Warming — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

### Modeling Worst-Case 1 hr Emissions

| | |
|---|---|
| NOx (g/sec) | 0.2 |
| CO (g/sec) | 0.2 |
| $SO_2$ (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

| | |
|---|---|
| $SO_2$ (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

| | |
|---|---|
| CO (lb/8-hr) | 12.96 |
| CO (g/sec) | 0.2 |

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

| | |
|---|---|
| $SO_2$ (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.

## Gasifier Warming — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

**Modeling Annual Average Emissions**

| | |
|---|---|
| NOx (g/sec) | 0.1 |
| CO (g/sec) | 0.0419 |
| VOC (g/sec) | 0.0033 |
| $SO_2$ (g/sec) | 0.0010 |
| $PM_{10} = PM_{2.5}$ (g/sec) | 0.0037 |

Pounds per year assumes 1,800 hours of annual normal operation.

## Cooling Towers — Emissions Summary

*Hydrogen Energy, Inc* — *6/30/2009*
*HECA Project*

### 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 | Process Area | 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 |
| **Process Area 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.

**Parameters**

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

| Modeling Worst-Case 24 Hour Emissions | Power Block | Process Area | 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.

| Modeling Worst-Case Annual Emissions | Power Block | Process Area | 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.

## Emergency Diesel Generators — Emissions Summary

*Hydrogen Energy, Inc*
*HECA Project*

*6/30/2009*

**Emergency Generator - Expected Emergency Operation and Maintenance**

| | | |
|---|---|---|
| **Total Hours of Operation** | 50 | hr/yr |
| **Generator Specification** | 2,800 | Bhp |

| Hours per Qtr | | | |
|---|---|---|---|
| **Q1** | **Q2** | **Q3** | **Q4** |
| 12.5 | 12.5 | 12.5 | 12.5 |

Assuming equal operation in each quarter

**Generator Pollutant Emission Factors (per generator)**

| | |
|---|---|
| NOx (g/Bhp/hr) | 0.50 |
| CO (g/Bhp/hr) | 0.29 |
| VOC (g/Bhp/hr) | 0.11 |
| $SO_2$ (g/Bhp/hr) | N/A |
| $PM_{10} = PM_{2.5}$ (g/Bhp/hr) | 0.03 |

**Generator Pollutant Emission Rates (per generator)**

| | Generator Emissions | | | | |
|---|---|---|---|---|---|
| **Pollutant** | **lb/hr** | **lb/day** | **lb/yr** | **ton/qtr** | **ton/yr** |
| NOx | 3.09 | 6.17 | 154.32 | 0.02 | 0.1 |
| CO | 1.79 | 3.58 | 89.51 | 0.01 | 0.04 |
| VOC | 0.68 | 1.36 | 33.95 | 0.00 | 0.02 |
| $SO_2$ | 0.03 | 0.06 | 1.40 | 0.00 | 0.001 |
| $PM_{10} = PM_{2.5}$ | 0.16 | 0.32 | 8.02 | 0.00 | 0.00 |

| | | |
|---|---|---|
| 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) | 0.2 |
| $SO_2$ (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) | 3.58 |
| CO (g/sec) | 0.06 |

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) | 0.32 |
| $PM_{10} = PM_{2.5}$ (g/sec) | 0.002 |

Only $SO_2$ and PM are considered for an average 24-hour Ambient Air Quality Standard.
Pounds per 24-hr assumes two (2) hours of operation.

**Modeling Annual Average Emissions (per generator)**

| | |
|---|---|
| NOx (g/sec) | 0.002 |
| CO (g/sec) | 0.001 |
| VOC (g/sec) | 0.000 |
| $SO_2$ (g/sec) | 0.00002 |
| $PM_{10} = PM_{2.5}$ (g/sec) | 0.0001 |

Pounds per year assumes 50 hours of operation.

# Emergency Diesel Firewater Pump — Emissic

*Hydrogen Energy, Inc*
*HECA Project*

**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** |
| 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 |

**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

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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.

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**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.

## Intermittent $CO_2$ Vent — Emissions Summary

*Hydrogen Energy, Inc*
*HECA Project*

*6/30/2009*

**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** |
| 5.25 | 5.25 | 5.25 | 5.25 |

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 |

**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 |

## Intermittent $CO_2$ Vent

**Emissions Summary**

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*6/30/2009*

### 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.

## Feedstock - Dust Collection — Emissions Summary

*Hydrogen Energy, Inc*
*HECA Project*

*6/30/2009*

**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 | 6,463 | 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 | 5.72 | 404.40 | 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 |
|---|---|---|---|
| $PM_{10}$ | **7,143.0** | **0.9** | **3.6** |
| $PM_{2.5}$ | **2085.7** | **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.

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*6/30/2009*

**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) | 5.72 | 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) | 1.672 | 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) | 404.40 | 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) | 118.085 | 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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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 | | 50 | hr/yr | | | |
| HRSG Heat Input | | 1,998 | MMBtu/hr | | | |
| $CO_2$ = | 5,274 | tonne/yr | | | | |
| $CH_4$ = | 1 | tonne/yr = | 12 | tonne $CO_2e$/yr | | |
| $N_2O$ = | 0.01 | tonne/yr = | 3 | tonne $CO_2e$/yr | Total tonne $CO_2e$/yr = | 5,290 |

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 startup and shutdown operating hours are estimated at 50 hr/yr.
HRSG heat input rate is assumed to be the maximum heat input rate firing natural gas, which corresponds to winter minimum (20 F).

### Auxiliary CTG

| | | | | | | |
|---|---|---|---|---|---|---|
| Operating Hours | | 4,110 | hr/yr | | | |
| HRSG Heat Input | | 911 | MMBtu/hr | | | |
| $CO_2$ = | 197,620 | tonne/yr | | | | |
| $CH_4$ = | 22 | tonne/yr = | 464 | tonne $CO_2e$/yr | | |
| $N_2O$ = | 0.4 | tonne/yr = | 116 | tonne $CO_2e$/yr | Total tonne $CO_2e$/yr = | 198,200 |

Average annual GHG operational emissions are calculated using yearly average (65 F) at 100 % load, with evaporative cooling.

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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 | | | |
| HRSG 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**

| | | | | | | |
|---|---|---|---|---|---|---|
| Operating Hours | | 50 | hr/yr | | | |
| HRSG Heat Input | | 2,800 | Bhp | | | |
| $CO_2$ = | 3,201 | lb/hr = | 73 | tonne $CO_2$/yr | | |
| $CH_4$ = | 0.09 | lb/hr = | 0.045 | tonne $CO_2e$/yr | | |
| $N_2O$ = | 0.03 | lb/hr = | 0.2218 | tonne $CO_2e$/yr | Total tonne $CO_2e$/yr* = | 146 |

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 | | | |
| HRSG 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 | | | |
| HRSG 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 | | 115,500 | MMBtu/yr | | | |
| $CO_2$ = | 6,098 | tonne/yr | | | | |
| $CH_4$ = | 0.7 | tonne/yr = | 14 | tonne $CO_2e$/yr | | |
| $N_2O$ = | 0.01 | tonne/yr = | 4 | tonne $CO_2e$/yr | Total tonne $CO_2e$/yr = | 6,116 |

GHG emissions from flaring events are conservatively estimated using GHG emission factors for natural gas combustion.

**SRU Flare**

| | | | | | | |
|---|---|---|---|---|---|---|
| **Pilot Operation** | | | | | | |
| Operating Hours | | 8,760 | hr/yr | | | |
| HRSG 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.

**Flaring Events (assist gas)**

| | | |
|---|---|---|
| Operating Hours | 6 | hr/yr |
| HRSG Heat Input | 36 | MMBtu/hr |

| | | | | | | |
|---|---|---|---|---|---|---|
| $CO_2$ = | 11 | tonne/yr | | | | |
| $CH_4$ = | 0.001 | tonne/yr = | 0.03 | tonne $CO_2e$/yr | | |
| $N_2O$ = | 0.00002 | tonne/yr = | 0.007 | tonne $CO_2e$/yr | Total tonne $CO_2e$/yr = | 11 |

**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 | 6 | hr/yr |

| | |
|---|---|
| Total tonne $CO_2e$/yr = | 26 |

GHG emissions from flaring events are conservatively estimated using GHG emission factors for natural gas combustion.
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.

**Rectisol Flare**

| | | | | | | |
|---|---|---|---|---|---|---|
| **Pilot Operation** | | | | | | |
| Operating Hours | 8,760 | hr/yr | | | | |
| HRSG 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 |

GHG emissions from flaring events are conservatively estimated using GHG emission factors for natural gas combustion.

**Tail Gas Thermal Oxidizer**

| | | | | | | |
|---|---|---|---|---|---|---|
| **Process Vent Disposal Emissions** | | | | | | |
| Operating Hours | 8,760 | hr/yr | | | | |
| HRSG Heat Input | 10 | MMBtu/hr | | | | |
| $CO_2$ = | 4,625 | tonne/yr | | | | |
| $CH_4$ = | 0.52 | tonne/yr = | 10.9 | tonne $CO_2e$/yr | | |
| $N_2O$ = | 0.0088 | tonne/yr = | 2.7 | tonne $CO_2e$/yr | Total tonne $CO_2e$/yr = | 4,638 |
| **SRU Startup Waste Gas Disposal** | | | | | | |
| Operating Hours | 300 | hr/yr | | | | |
| HRSG Heat Input | 10 | MMBtu/hr | | | | |

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.

| | | | | | | |
|---|---|---|---|---|---|---|
| $CO_2$ = | 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 flaring events are conservatively estimated using GHG emission factors for natural gas combustion.

**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 21 days per year venting at full rate.

**Gasifier Warming**

| | | | | | | |
|---|---|---|---|---|---|---|
| Operating Hours | | 1,800 | hr/yr | | | |
| HRSG Heat Input | | 18 | MMBtu/hr | | | |
| $CO_2$ = | 1,711 | tonne/yr | | | | |
| $CH_4$ = | 0 | tonne/yr = | 4 | tonne $CO_2e$/yr | | |
| $N_2O$ = | 0.00 | tonne/yr = | 1 | tonne $CO_2e$/yr | Total tonne $CO_2e$/yr = | 1,716 |

| | |
|---|---|
| **Total tonne $CO_2e$/yr =** | **383,317** |

## Summary of Truck Emissions - HECA — Emissions Summary

*Hydrogen Energy International LLC* — *6/30/2009*
*HECA Project*

**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) | 0.9659 | | 0.568 | |
| 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 | 35500 | 2,900 | 2900 |

**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 | Default value from URBEMIS 9.2 for Kern County |
| | 0.19 | g/VMT | Default value from URBEMIS 9.2 for Kern County |

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**EMFAC2007 Emission Factors (g/mi or g/idle-hour)**

| Pollutant | Coke and Coal Trucks (@ 10 mph) | | Onsite Gasifier Solids Handling (@ 5 mph) | |
|---|---|---|---|---|
| | Running Emissions | Idling Emissions | Running Emissions | Idling Emissions |
| CO | 8.289 | 47.47 | 12.05 | 47.47 |
| NOx | 16.59 | 115.98 | 23.645 | 115.98 |
| SOx | 0.03 | 0.062 | 0.04 | 0.062 |
| PM10 * | 1.09 | 1.115 | 1.47 | 1.115 |
| PM2.5 | 0.794 | 1.026 | 1.142 | 1.026 |

** PM10 iincludes 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 ( 0.84 mile route) | Idling Emissions (at each Idle Point) | Running Emissions ( 0.568 mile route) | Idling Emissions (at each Idle Point) |
| CO | 0.040 | 0.028 | 0.004 | 0.002 |
| NOx | 0.080 | 0.068 | 0.007 | 0.005 |
| SOx | 1.4E-04 | 3.6E-05 | 1.2E-05 | 2.9E-06 |
| PM10 | 0.005 | 0.001 | 0.000 | 5.2E-05 |
| PM2.5 | 0.004 | 0.001 | 3.60E-04 | 4.8E-05 |

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

| Pollutant | Coke and Coal Trucks (@ 10 mph) | | Onsite Gasifier Solids Handling (@ 5 mph) | |
|---|---|---|---|---|
| | Running Emissions ( 0.84 mile route) | Idling Emissions (at each Idle Point) | Running Emissions ( 0.568 mile route) | Idling Emissions (at each Idle Point) |
| CO | 0.040 | 0.028 | 0.004 | 0.003 |
| NOx | 0.080 | 0.068 | 0.009 | 0.006 |
| SOx | 1.4E-04 | 3.6E-05 | 1.4E-05 | 3.3E-06 |
| PM10 | 0.005 | 0.001 | 0.001 | 6.0E-05 |
| PM2.5 | 0.004 | 0.001 | 4.20E-04 | 5.5E-05 |

*Hydrogen Energy International LLC*
*HECA Project*
*6/30/2009*

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

| Pollutant | Coke and Coal Trucks (@ 10 mph) | | Onsite Gasifier Solids Handling (@ 5 mph) | |
|---|---|---|---|---|
| | Running Emissions ( 0.84 mile route) | Idling Emissions (at each Idle Point) | Running Emissions ( 0.568 mile route) | Idling Emissions (at each Idle Point) |
| CO | 0.040 | 0.028 | 0.003 | 0.002 |
| NOx | 0.080 | 0.068 | 0.006 | 0.004 |
| SOx | 1.4E-04 | 3.6E-05 | 9.5E-06 | 2.3E-06 |
| PM10 | 0.005 | 0.001 | 3.8E-04 | 4.2E-05 |
| PM2.5 | 0.004 | 0.001 | 2.9E-04 | 3.9E-05 |

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

| Pollutant | Coke and Coal Trucks (@ 10 mph) | | Onsite Gasifier Solids Handling (@ 5 mph) | |
|---|---|---|---|---|
| | Running Emissions ( 0.84 mile route) | Idling Emissions (at each Idle Point) | Running Emissions ( 0.568 mile route) | Idling Emissions (at each Idle Point) |
| CO | 0.017 | 0.012 | 0.003 | 0.002 |
| NOx | 0.033 | 0.028 | 0.006 | 0.004 |
| SOx | 6.0E-05 | 1.5E-05 | 9.1E-06 | 2.2E-06 |
| PM10 | 0.002 | 2.7E-04 | 3.6E-04 | 4.0E-05 |
| PM2.5 | 0.002 | 2.5E-04 | 2.8E-04 | 3.7E-05 |

**Annual Emission Rates for AERMOD (g/s)**

| Pollutant | Coke and Coal Trucks (@ 10 mph) | | Onsite Gasifier Solids Handling (@ 5 mph) | |
|---|---|---|---|---|
| | Running Emissions ( 0.84 mile route) | Idling Emissions (at each Idle Point) | Running Emissions ( 0.568 mile route) | Idling Emissions (at each Idle Point) |
| CO | 0.009 | 0.006 | 0.001 | 0.000 |
| NOx | 0.018 | 0.015 | 0.001 | 0.001 |
| SOx | 3.3E-05 | 8.1E-06 | 1.9E-06 | 4.8E-07 |
| PM10 | 0.001 | 1.5E-04 | 7.7E-05 | 8.5E-06 |
| PM2.5 | 0.001 | 1.3E-04 | 6.0E-05 | 7.9E-06 |

# Appendix C

# Modeling Protocol

# AIR QUALITY MODELING PROTOCOL FOR THE HYDROGEN ENERGY CALIFORNIA (HECA) PROJECT

# AIR QUALITY MODELING PROTOCOL FOR THE HECA POWER PROJECT KERN COUNTY, CALIFORNIA

*Prepared For:*

- San Joaquin Valley Air Pollution Control District
- California Energy Commission
- U.S. Environmental Protection Agency Region IX
- U.S. Forest Service
- National Park Service

*Prepared on behalf of*

**Hydrogen Energy International LLC**

February 6, 2009

URS

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| | |
|---|---|
| $\mu g/m^3$ | Micrograms per cubic meter |
| AAQS | Ambient Air Quality Standards |
| AERMOD | American Meteorological Society/Environmental Protection Agency Regulatory Model |
| AFC | Application for certification |
| APN | Assessor Parcel Number |
| AQRV | Air quality related values |
| ARB | Air Resources Board |
| ARM | Ambient Ratio Method |
| ATC | Authority to construct |
| BACT | Best available control technology |
| BART | Best available retrofit technology |
| BPAE | BP Alternative Energy |
| BPIP | Building profile input program |
| BPIP-Prime | Building Parameter Input Program – Prime |
| CAAQS | California Ambient Air Quality Standards |
| CARB | California Air Resources Board |
| CEC | California Energy Commission |
| CO | Carbon monoxide |
| $CO_2$ | Carbon dioxide |
| CTG | Combustion turbine generator |
| °C | degrees Celsius |
| DAT | Deposition analysis threshold |
| DCS | Distributed Control System |
| DEGADIS | Dense gas dispersion model |
| DEM | Digital elevation model |
| DOC | Determination of compliance |
| EC | Element carbon |
| ERC | Emission reduction credit |
| FLAG | Federal land manager air quality related values group |
| FLM | Federal Land Manager |
| °F | Degree Fahrenheit |
| GEP | Good engineering practice |
| g/s | Gram per second |
| $H_2S$ | Hydrogen Sulfide |
| HARP | Hotspots analysis and reporting program |
| HECA | Hydrogen Energy California |
| HEI | Hydrogen Energy Inc |
| HHV | Higher heating value |
| HI | Hazard Indices |
| $HNO_3$ | Nitric acid |
| HRA | Health risk assessment |
| HRSG | Heat recovery steam generator |
| IGCC | Integrated gasification combined cycle |
| ISCST3 | Industrial Source Complex Short Term 3rd version |

| | |
|---|---|
| ISO | International Organization for Standardization |
| IWAQM | Interagency Workgroup on Air Quality Modeling |
| km | Kilometers |
| LAC | Level of acceptable change |
| LCC | Lambert Conformal Conic |
| LORS | Laws, ordinances, regulations, and standards |
| LULC | Land use land cover |
| MEI | Maximally exposed individual |
| m | Meters |
| mm | Millimeters |
| MICR | Minimum individual cancer risk |
| MM5 | Mesoscale meteorological |
| MMBtu/hr | Million British thermal unit per hour |
| MW | Megawatt |
| NAAQS | National Ambient Air Quality Standards |
| $NH_4NO_3$ | Ammonium nitrate |
| $(NH_4)_2SO_4$ | Ammonium sulfate |
| NNSR | Non-attainment New Source Review |
| $NO_2$ | Nitrogen dioxide |
| $NO_3$ | Nitrate |
| $NO_x$ | Nitrogen oxides |
| NPS | National Park Service |
| NSR | New source review |
| NWS | National Weather Service |
| $O_3$ | Ozone |
| OEHHA | Office of Environmental Health Hazard Assessment |
| OLM | Ozone limiting method |
| Pb | Lead |
| $PM_{2.5}$ | Particulate matter less than 2.5 μm in diameter |
| $PM_{10}$ | Particulate matter less than 10 μm in diameter |
| ppb | Parts per billion |
| ppm | Parts per million |
| PMS | Particulate Matter Speciation |
| PSD | Prevention of significant deterioration |
| PTE | Potential to emit |
| RH | Relative humidity |
| ROC | Reactive organic compound |
| SCR | Selective catalytic reduction |
| SIL | Significant impact level |
| SJVAPCD | San Joaquin Valley Air Pollution Control District |
| $SO_2$ | Sulfur dioxide |
| $SO_x$ | Sulfur oxides |
| SOA | Secondary organic aerosol |
| STG | Steam turbine generator |
| TAC | Toxic air contaminants |

| | |
|---|---|
| T-BACT | Best available control technology for toxics |
| TGT | Tail gas treatment |
| tpy | Tons per year |
| TSP | Total suspended particles |
| USEPA | United States Environmental Protection Agency |
| USFS | United States Forest Service |
| USGS | United States Geological Survey |
| UTM | Universal Transverse Mercator |
| VOC | Volatile organic compound |
| WRAP | Western regional air partnership |
| ZOI | Zone of impact |

# SECTION 1 INTRODUCTION

## 1.1 BACKGROUND

This document is being submitted to your agency for review and approval. Your agency received a similar document in April 2008 which was commented on and approved. This document was modified from the 2008 version because a new site location about 2.5 km north of the previous site has been selected for the project. All agency comments received for the previous version have been incorporated into this modification. The modeling methodology is unchanged. Ambient monitoring data has been updated.

Hydrogen Energy California (HECA) will be a nominal net 250-megawatt (MW) integrated gasification combined cycle (IGCC) power plant to be constructed on an approximately 1,100-acre parcel near an oil producing area in Kern County, Southern California. The Project will be owned and operated by Hydrogen Energy International LLC, a joint venture of BP Alternative Energy (BPAE) and Rio Tinto. HECA will integrate a gasification block consisting of two active gasification trains (and one spare in hot standby mode) and associated equipment and a power block consisting of one hydrogen-fired or natural gas-fired, or a combination of hydrogen and natural gas, combustion turbine-electrical generator (CTG), duct-fired heat recovery steam generator (HRSG), one condensing steam turbine generator (STG) and associated equipment. HECA will be permitted as a base loaded facility. A blend of petroleum coke and coal or 100 percent petroleum coke will be the primary feedstock to the gasifier. The Carbon Dioxide ($CO_2$) gas exiting the gasifier will be separated from the hydrogen stream and injected into the nearby oil fields to reduce greenhouse gas emissions from the project and for enhanced recovery of oil. Natural gas will be used in the CTG during startups and at other times in the CTG and the HRSG to supplement the hydrogen fuel. The project will also include an auxiliary CTG for electrical power production for on-site and off-site use. This will be a natural gas-fired simple cycle gas turbine GE model number LMS-100 with an output of approximately 100 MW.

The HECA site area is approximately 543 security fenced acres within a 1,100 acre property located near an oil producing area in Kern County, Southern California. It is 34 km southwest of Bakersfield near Buttonwillow. The parcel is just west of Tupman Road and southeast of the town of Buttonwillow. The legal description of the property is as follows: Southeast ¼ of Section 9 (only the portion north of the West Side Canal), Section 10 (excluding 5 acres in the northwest quadrant), and Section 15 (only the portion north of the West Side Canal) within Township 30 South, Range 24 East in Kern County. The Assessor's Parcel Numbers (APN) are:

- 159-040-02
- 159-040-04
- 159-040-11
- 159-040-16
- 159-040-18
- 159-190-09

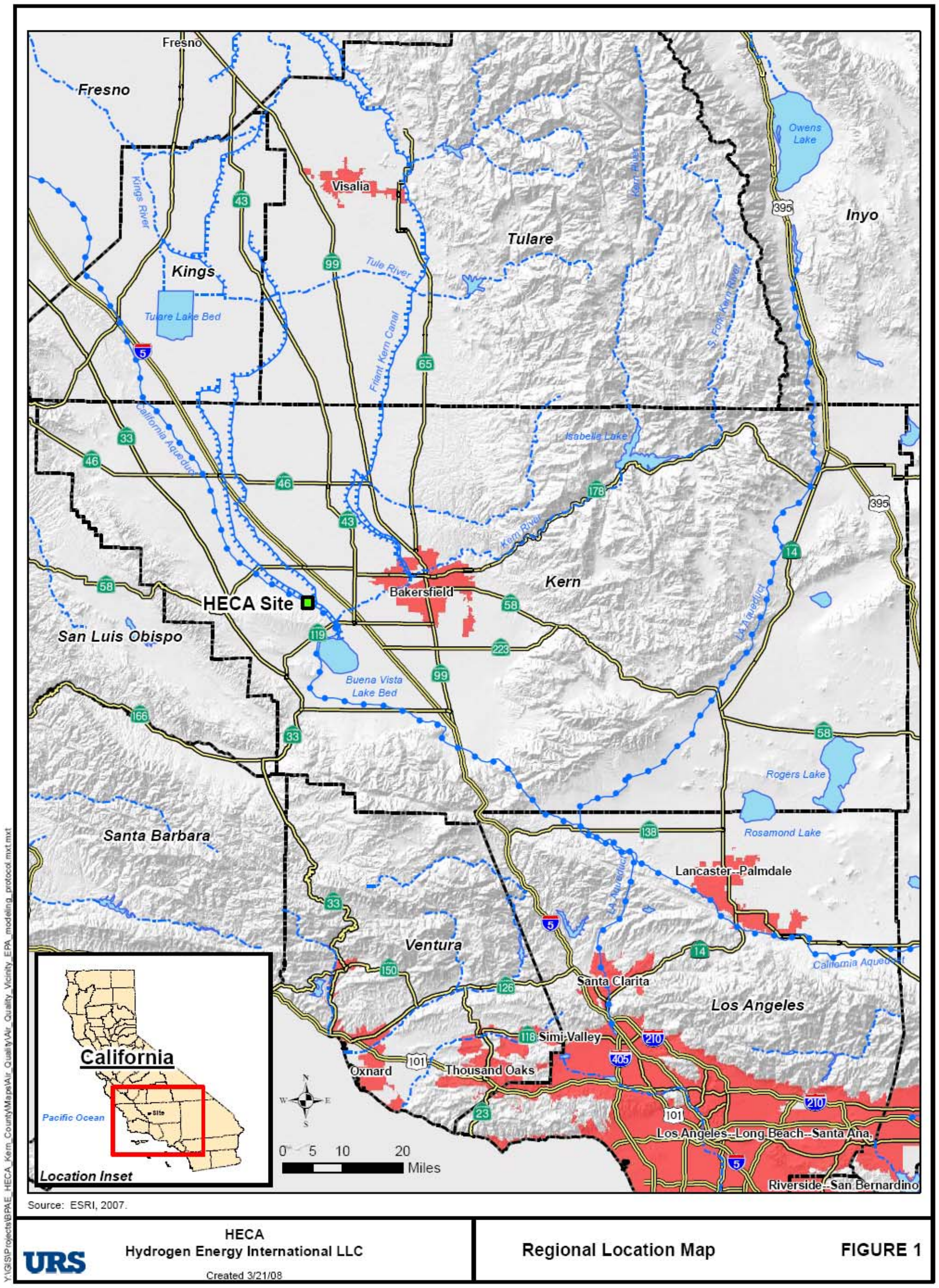
The project is subject to the site licensing requirements of the California Energy Commission (CEC). The CEC will coordinate its independent air quality evaluations with the San Joaquin Valley Air Pollution Control District (SJVAPCD) through the Determination of Compliance (DOC) process. The HECA will be a Major Source as this term is defined in the United States Environmental Protection Agency's (USEPA) Prevention of Significant Deterioration (PSD) regulations, because it is a categorical source (fossil-fuel fired steam electric plant of more than 250 MMBtu/hr heat input), and will have a potential to emit more than 100 tons per year (tpy) of nitrogen oxides ($NO_x$), particulate matter of diameter less than or equal to 10 microns ($PM_{10}$) and carbon monoxide (CO). Volatile Organic Compounds (VOC) and sulfur oxides ($SO_x$) will be emitted in lesser amounts. Because the project will emit more than 100 tpy of at least one attainment pollutant, PSD analyses are also required for any other criteria pollutants for which the proposed facility's Potential to Emit exceeds PSD significant emission levels.

The annual emissions estimates described above are based on the following annual operating parameters:

- One gasification block cold startup and shutdown each year;
- Up to 12 gasifier hot restarts per year;
- Up to 3 cold power block starts, 2 warm power block starts and 5 shutdowns per year of the CTG;
- Up to 7,500 hours/year at steady state operation of the power block;
- Up to 8,520 hours/year operation of the cooling towers;
- Up to 4,000 hours per year operation of the Auxiliary CTG
- Up to 25 percent annual capacity of the auxiliary boiler; and
- Intermittent testing of the emergency diesel generator and the emergency diesel fire pump.

Because the project triggers PSD review, the air dispersion modeling for this project will be conducted in conformance with PSD requirements. For example, worst-case predicted impacts will be compared with the applicable monitoring exemption limits to demonstrate that the project will be exempt from the requirements relating to pre-construction ambient air quality monitoring. The PSD regulations apply only to those pollutants for which the project area is in attainment of the National Ambient Air Quality Standards (NAAQS). State and local new source review (NSR) and non-attainment NSR (NNSR) regulations potentially apply to all criteria pollutants, depending on the quantity of pollutants emitted.

**Figure 1**
**General Vicinity – Hydrogen Energy California**



The area around HECA is classified as attainment with respect to the NAAQS for nitrogen dioxide ($NO_2$), particulate matter with diameter less than 10 micrometers ($PM_{10}$), CO, and $SO_2$, and non-attainment for ozone ($O_3$) and particulate matter with diameter less than 2.5 micrometers ($PM_{2.5}$). With respect to the California Ambient Air Quality Standards (CAAQS), the area around HECA is classified as attainment for $NO_2$, CO, sulfates, lead (Pb), hydrogen sulfide, and $SO_2$, and non-attainment for $O_3$, $PM_{10}$, and $PM_{2.5}$. $NO_2$ and $SO_2$ are regulated as $PM_{10}$ precursors, and $NO_2$ and volatile organic compounds (VOC) as $O_3$ precursors. Project emissions of non-attainment pollutants and their precursors will be offset to satisfy federal and local NNSR regulations.

## 1.2 PURPOSE

The CEC, SJVAPCD and USEPA all require the use of atmospheric dispersion modeling to demonstrate that a new power generation facility or modification to an existing facility will comply with applicable air quality standards. These agencies also require an assessment of the potential impacts on human health from the toxic air contaminants that may be emitted by such projects. In addition, CEC power plant siting regulations require modeling to evaluate the cumulative impacts of the proposed project with other new and reasonably foreseeable projects within 10 km (6 miles) of the project site.

This document summarizes the procedures that are proposed for the air dispersion modeling for project certification and permitting. Modeling of both operation and construction emissions due to the proposed power plant will be performed in accordance with CEC and SJVAPCD guidance. This Protocol is being submitted to the CEC and SJVAPCD for their review and comment prior to completion of the applicable permit applications. The Protocol is also being provided to USEPA Region IX, U.S. Forest Service and National Park Service, because of the need to obtain a separate PSD permit for the proposed project. The proposed model selection and modeling approach is based on review of applicable regulations and agency guidance documents, and recent discussions with staffs of the responsible agencies.

# SECTION 2 PROJECT DESCRIPTION

## 2.1 PROJECT LOCATION

The location of the proposed project is shown on Figure 1, which also illustrates the project site, and nearby roads and other features. The HECA site is approximately 1,100 acres in size. The site is accessible from Bakersfield via State Highway 119 westbound and west of Tupman Road.

## 2.2 DESCRIPTION OF THE PROPOSED SOURCES

Figure 2 shows the preliminary layout of the proposed power plant, including property lines and the locations of all major equipment. The process diagram of the project is shown in Figure 3. Emission points are identified on Figure 2 by number and shown in the legend. These numbers are used in the discussions below.

The proposed power generation facility (power block) will consist of one GE Model 7FB or equivalent Siemens CTG with an ISO base load gross output of approximately 230 MW. The CTG will be designed and constructed to burn multiple fuels (i.e., a combination of fuels ranging from hydrogen to pipeline-quality natural gas and mixtures of the two) with an evaporative cooling system installed on the inlet air for use when the ambient temperatures exceed 59°F. The CTG will be followed by a Heat Recovery Steam Generator (HRSG). The HRGS will also be designed to burn the same multiple fuels as the CTG. The maximum fuel flow rate for the CTG and HRSG will be approximately 1,850 MMBtu/hr and 500 MMBtu/hr (higher heating value, HHV), respectively. Exhaust from the CTG/HRSG will exit through a stack with a height of 213 feet (Emission Point No. 4).

An air/nitrogen mixture is supplied to the CTG through an inlet air filter, inlet air evaporative cooling system, compressor section of the combustion turbine and then exits through the compressor discharge casing to the combustion chambers. Fuel is also supplied to the combustion chambers where it is ignited with the compressed air/nitrogen mixture, expanding through the turbine blades, driving the turbine, electricity generator, and the CTG compressor. Exhaust gas from the CTG is directed through internally insulated ductwork to the HRSG. Steam generated in the HRSG is admitted to a steam turbine generator (STG) for electric power generation. The STG system, rated at approximately 150 MW consists of a steam turbine, gland steam system, lube oil system, hydraulic control system, and a hydrogen cooled generator with all required accessories.

A diffusion combustor system using nitrogen as a diluent when firing hydrogen and using steam as a diluent when firing natural gas will be used to control the $NO_X$ emissions from the CTG. A selective catalytic reduction (SCR) system will be provided in the HRSG to further reduce the $NO_X$ emissions to the atmosphere. The SCR system for the HRSG will inject aqueous ammonia into the exhaust gas stream upstream of a catalyst bed to reduce $NO_X$ to inert nitrogen and water. An oxidation catalyst system will also be incorporated into the air quality control system to control emissions of CO and ROGs.

The auxiliary CTG will be fired exclusively on natural gas and will be equipped with water injection and selective catalytic reduction (SCR) for the control of $NO_x$ emissions and an oxidation catalyst for control emissions of CO and ROGs. The auxiliary CTG will operate in simple cycle mode and will have an exhaust stack with a height of 110 feet (Emission Point No. 12).

An auxiliary boiler (Emission Point No. 6) will provide steam to facilitate CTG startup and for other purposes. The auxiliary boiler will be designed to burn a single fuel (i.e., pipeline-quality natural gas) at the design maximum fuel flow rate of 142 MMBtu/hr HHV. The auxiliary boiler will be equipped with ultra-low $NO_X$ combustors and will have an estimated annual capacity of 25 percent.

HECA will also incorporate a thermal oxidizer (Emission Point No. 7) on the tail gas treatment (TGT) unit to control emissions during startup of the TGT unit. After the TGT unit is started, emissions from the TGT thermal oxidizer will cease being emitted and will be returned to the process. A Gasification Flare (Emission Point No. 10) will be used to safely dispose of gas streams during startup, shutdown and unplanned upsets or emergency events. A Sulfur Recovery Unit (SRU) Flare (Emission Point No. 9) will be used to safely dispose of gas streams containing sulfur during startup and shutdown (such streams having first passed through an absorber or scrubbing unit for sulfur removal) and gas streams containing sulfur during unplanned upsets or emergency events. A Rectisol Flare (Emission Point No. 13) will be used to safely dispose of low temperature gas streams during unplanned upsets or emergency events.

Each of the three gasification trains will have one natural-gas fired burner used to warm up the gasification train upon start-up (Emission Point Nos. 11a -11c). These burners will not operate when the gasification train is operating.

A 16-celled mechanical draft cooling tower (Emission Point No. 2) will be installed to perform the required cooling for the CTGs, STG, and associated equipment. Other sources of emissions will include a 4-celled mechanical draft cooling tower for the air separation unit (Emission Point No. 1), diesel-fired internal combustion engine drivers for an emergency fire pump rated at about 550 horsepower (Emission Point No. 5), and two 1 MW each emergency generators (Emission Point No. 3).

A $CO_2$ vent stack (Emission Point No. 8) will provide an alternative operating scenario for releasing the produced $CO_2$ when the $CO_2$ injection system is unavailable. The $CO_2$ vent will enable HECA to operate for brief periods rather than be disabled by a gasifier shutdown and subsequent gasifier restart. The $CO_2$ vent exhaust stream will be nearly all $CO_2$, with small amounts of CO and Hydrogen Sulfide ($H_2S$).

In addition to the sources above, there will be emissions of $PM_{10}$ from feedstock and gasifier solids materials handling operations. These operations include bulk material unloading, loading, belt conveying, belt transfer points, silo loading and reclaim. The $PM_{10}$ emissions will be controlled with the help of a dust collection system consisting of hoods and baghouses.

**Figure 2**
**HECA Facility Plot Plan**

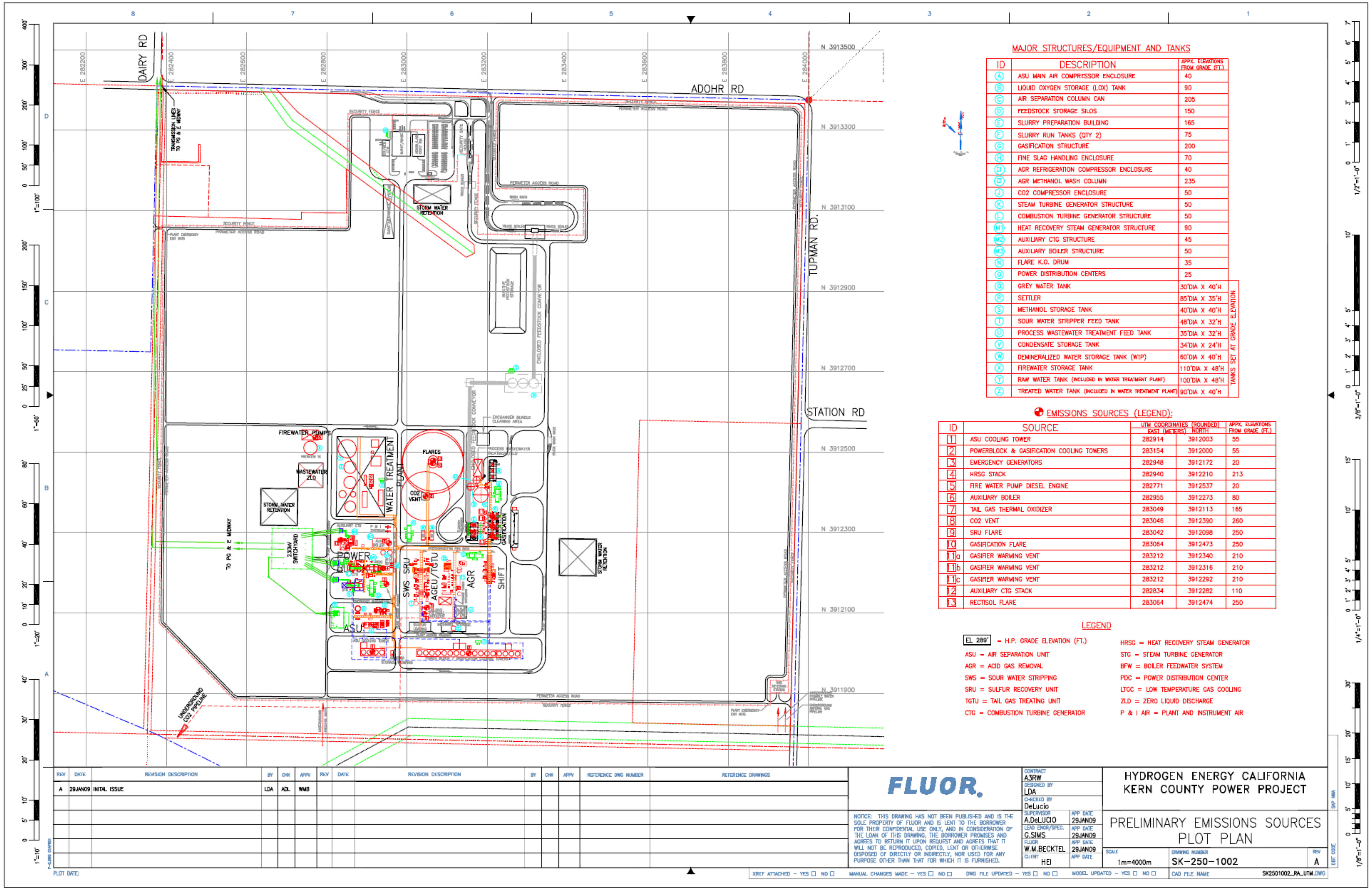
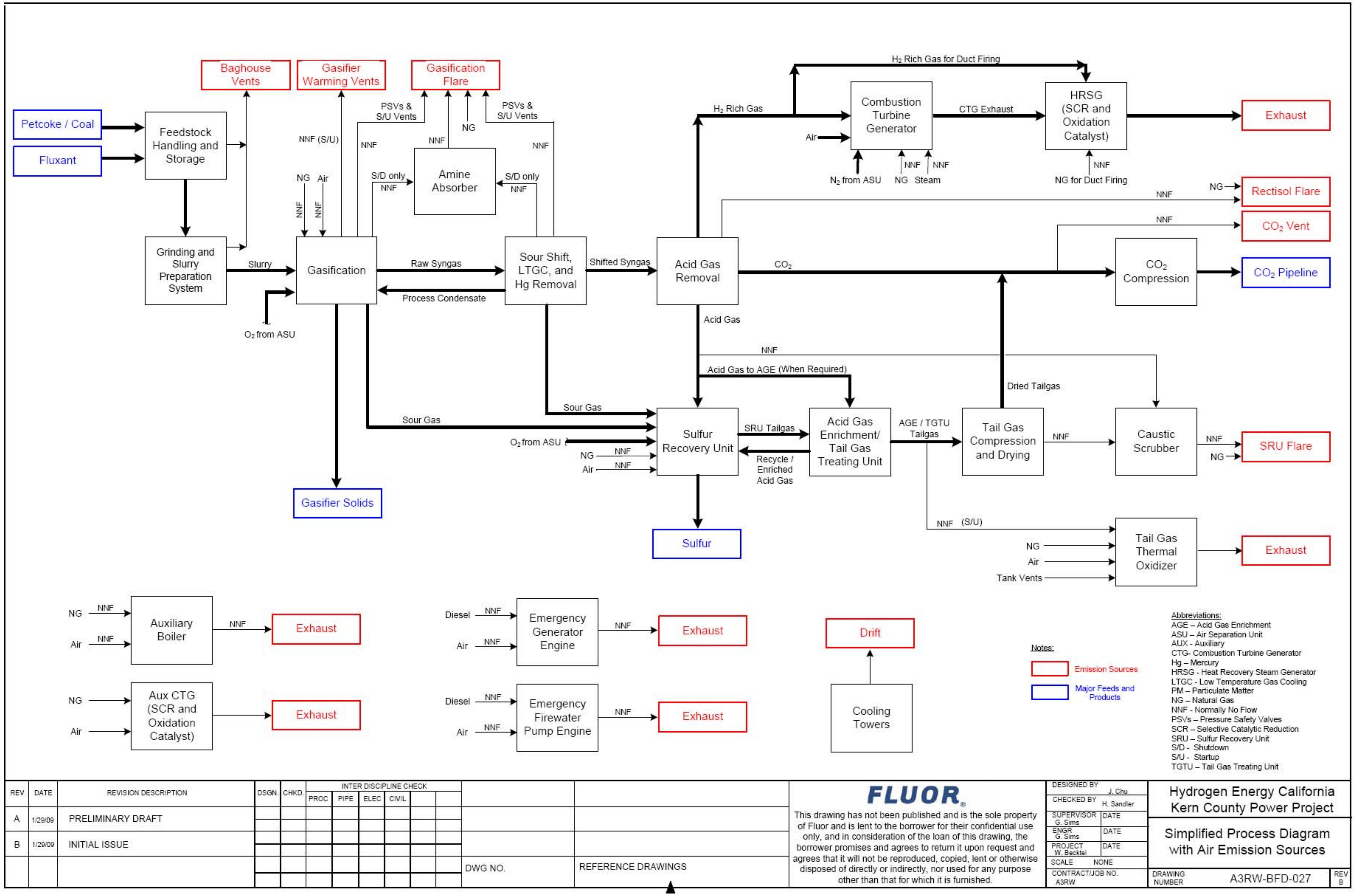


**Figure 3**
**HECA Process Diagram**



# SECTION 3 REGULATORY SETTING

## 3.1 CALIFORNIA ENERGY COMMISSION REQUIREMENTS

For projects with electrical power generation capacity greater than 50 MW, CEC requires that applicants prepare a comprehensive Application for Certification (AFC) document addressing the proposed project's environmental and engineering features. An AFC must include the following air quality information (CEC, 1997):

- A description of the project, including project emissions of air pollutants and greenhouse gases, fuel type(s), control technologies and stack characteristics;
- The basis for all emission estimates and/or calculations;
- An analysis of Best Available Control Technology (BACT) according to San Joaquin Valley Air Pollution Control District (SJVAPCD) Rules;
- Existing baseline air quality data for all regulated pollutants;
- Existing meteorological data, including temperature, wind speed and direction, and mixing height;
- A listing of applicable laws, ordinances, regulations, standards (LORS), and a determination of compliance with all applicable LORS;
- An emissions offset strategy;
- An air quality impact assessment (i.e., national and state ambient air quality standards [AAQS] and PSD review) and protocol for the assessment of cumulative impacts of the proposed project along with permitted and under construction projects within a 10 km radius; and
- An analysis of human exposure to air toxics (i.e., health risk assessment [HRA]).

For HECA, the air quality impact assessment, the cumulative impacts assessment, and the HRA will be performed using dispersion models.

## 3.2 SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT REQUIREMENTS

The SJVAPCD has promulgated NSR requirements under Rule 2201. In general, all equipment with the potential to emit air pollutants is subject to the requirements of this rule, which has the following major requirements that potentially apply to new sources such as HECA:

- Installation of BACT,
- Ambient air quality impact modeling to demonstrate compliance with NAAQS and CAAQS and to evaluate impacts to plume visibility in Class I areas near the proposed source(s),
- Emission offsets,
- Statewide compliance for all applicant-owned or operated facilities in California,

Assembly Bill 2588, California Air Toxics Hot Spots Program and SJVAPCD Rule 3110 establish allowable incremental health risks for new or modified sources of toxic air contaminant (TAC) emissions This rule specifies limits for maximum individual cancer risk (MICR), cancer burden, and non-carcinogenic acute and chronic hazard indices (HI) for new or modified sources of TAC emissions. The health risks resulting from project emissions, as demonstrated by means of an approved health risk assessment, must not exceed established threshold values.

## 3.3 U.S. ENVIRONMENTAL PROTECTION AGENCY REQUIREMENTS

USEPA has promulgated PSD regulations applicable to new Major Sources and Major Modifications to existing Major Sources. HECA will be a Major Source because it is a fossil-fuel fired steam electric plant of more than 250 MMBtu/hr heat input and will have the potential to emit more than 100 tpy of $NO_x$, and CO. Many of the PSD requirements are the same as the AFC and SJVAPCD Rule 2201 requirements described above (e.g., project description, BACT, ambient air quality standards analysis). However, PSD requires the following additional analyses:

- An analysis of the potential impacts from the new emissions from HECA relative to PSD Significant Impact Levels (SILs) and PSD Increments;
- An analysis of air quality related values (AQRV) to ensure the protection of visibility in federal Class I National Parks and National Wilderness Areas within 100 km of the proposed project;
- An evaluation of potential impacts on soils and vegetation of commercial and recreational value; and
- An evaluation of potential growth-inducing impacts.

# SECTION 4 AIR QUALITY IMPACT ANALYSIS FOR CLASS II AREAS

This section describes the dispersion models and modeling techniques that will be used in performing the near-field criteria pollutant impact analysis for HECA. The objectives of the modeling are to demonstrate that air emissions from HECA will not cause incremental impacts that exceed the Class II PSD Significant Impact Levels (SILs), nor contribute to exceedances of state and federal ambient air quality standards. A discussion of the Class II visibility analysis for the visible plumes from the cooling towers and the HRSG will be provided in the Visual Resources Section (Section 5.11) of the AFC.

In November 2005, the USEPA officially recognized the American Meteorological Society/ Environmental Protection Agency Regulatory Model (AERMOD) as the preferred dispersion model for regulatory applications, replacing the Industrial Source Complex Short Term 3 (ISCST3) model. Also, both CEC staff recommendations and the SJVAPCD guidance for air dispersion modeling (SJVAPCD, 2006) support the use of AERMOD for power plant licensing/permitting analyses. Accordingly, AERMOD (Version 07026) will be used for the dispersion modeling associated with HECA.

## 4.1 TURBINE SCREENING MODELING

An initial screening modeling analysis will be conducted to determine the turbine stack parameters for the most important project source, i.e., the CTG/HRSG that correspond to maximum ground-level pollutant concentrations. This information will be obtained by running a series of AERMOD simulations with the full meteorological input data set (see Section 4.6) with source inputs representing a range of different load conditions and ambient temperatures. The stack parameters that align with the highest offsite impact from these sources for each pollutant and averaging time period will be used in the subsequent refined modeling simulations.

## 4.2 REFINED MODELING

The purpose of the refined modeling analysis is to demonstrate that air emissions from HECA will not cause or contribute to an ambient air quality violation. The AERMOD model (version 07026) will be used for the refined modeling of criteria pollutants. Specific modeling procedures that will be used for evaluating project impacts versus the state and federal ambient air quality standards, PSD significance thresholds and applicable health risk criteria are discussed below. Table 4-1 shows the regulatory criteria that will be used to evaluate the significance of predicted pollutant concentrations.

Analysis of land uses adjacent to HECA was conducted in accordance with Section 8.2.8 of the Guideline on Air Quality Models (EPA-450/2-78-027R and Auer [1978]), EPA AERMOD implementation guide (2004), and its addendum (2006).

Based on the Auer land use procedure, more than 50 percent of the area within a 3-km radius of HECA power plant is classified as rural. Since the Auer classification scheme requires more than 50 percent of the area within the 3-km radius around a proposed new source to be non-rural for an urban classification, the rural mode will be used in the AERMOD modeling analyses. All regulatory default options will be used, including building and stack tip downwash, default wind speed profiles, exclusion of deposition and gravitational settling, consideration of buoyant plume rise, and complex terrain.

**Table 4-1**
**Relevant Ambient Air Quality Standards and Significance Levels**

| Pollutant | Averaging Time | CAAQS (a, b) | NAAQS (b, c) | PSD Class II Significance Impact Levels (µg/m³) | PSD Significant Emission Rates (tpy) | PSD Increments (µg/m³) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Class I | Class II |
| CO | 8-hour | 9.0 ppm (10,000 µg/m³) | 9.0 ppm (10,000 µg/m³) | 500 | 100 | | |
| | 1-hour | 20 ppm (23,000 µg/m³) | 35 ppm (40,000 µg/m³) | 2,000 | | | |
| $NO_2$[d] | Annual | 0.030 ppm (57 µg/m³) | 0.053 ppm (100 µg/m³) | 1 | 40 | 2.5 | 25 |
| | 1-hour | 0.18 ppm (339 µg/m³) | | | | | |
| $SO_2$ | Annual | | 0.03 ppm (80 µg/m³) | 1 | 40 | 2 | 20 |
| | 24-hour | 0.04 ppm[e] (105 µg/m³) | 0.14 ppm (365 µg/m³) | 5 | | 5 | 91 |
| | 3-hour | | 0.5 ppm (1,300 µg/m³) | 25 | | 25 | 512 |
| | 1-hour | 0.25 ppm (655 µg/m³) | | | | | |
| $PM_{10}$ | Annual | 20 µg/m³ | See footnote[e] | 1 | 15 | 4 | 17 |
| | 24-hour | 50 µg/m³ | 150 µg/m³ | 5 | | 8 | 30 |
| $PM_{2.5}$ | Annual | 12 µg/m³ | 15 µg/m³ | | | | |
| | 24-hour | | 35 µg/m³ | | | | |
| $O_3$ | 8-hour | 0.07 ppm (137 µg/m³) | 0.075 ppm (147 µg/m³) | See footnote[f] | | | |
| | 1-hour | 0.09 ppm (180 µg/m³) | See footnote[g] | | | | |
| $H_2S$ | 1-hour | 0.03 ppm[h] | | | | | |

Notes:

a. California standards for ozone (as volatile organic compound), carbon monoxide, sulfur dioxide (1-hour), nitrogen dioxide, and $PM_{10}$, are values that are not to be exceeded. The visibility standard is not to be equaled or exceeded.

b. Concentrations are expressed first in units in which they were promulgated. Equivalent units are given in parentheses and based on a reference temperature of 25°C and a reference pressure of 760 mm of mercury. All measurements of air quality area to be corrected to a reference temperature of 25°C and a reference pressure of 760 mm of mercury (1,013.2 millibars).

c. National standards, other than those for ozone and based on annual averages, are not to be exceeded more than once a year. The ozone standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is ≤ 1.

d. $NO_2$ is the compound regulated as a criteria pollutant; however, emissions are usually based on the sum of all $NO_x$.

e. The federal annual $PM_{10}$ standard was revoked by USEPA on October 17, 2006.

f. Modeling is required for any net increase of 100 tons per year or more of ROC subject to PSD.

g. New federal 8-hour ozone and fine particulate matter ($PM_{2.5}$) standards were promulgated by USEPA on July 18, 1997. The federal 1-hour ozone standard was revoked by USEPA on June 15, 2005.

h. The Hydrogen Sulfide ambient air quality standard is an odor based threshold instead of health based.

### 4.2.1 PSD Modeling Analyses

As the proposed project will trigger PSD as a Major Source, modeling will be required to determine whether its incremental impacts on ambient levels of attainment pollutants ($NO_2$, $SO_2$ and CO) will exceed Class II significant impact levels, or SILs. If these SILs were predicted to be exceeded, then an analysis of increment consumption due to all new sources that commenced operation since the local PSD baseline date would be required. However, it is anticipated that the increased emissions of these pollutants due to HECA will not cause incremental effects above the federal SILs.

### 4.2.2 Ambient Air Quality Standards Analysis

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

$NO_2$ impact estimates for both the 1-hour and annual averaging times will be modeled by executing AERMOD with the USEPA ozone limiting method (OLM) option for both hourly and annual impacts. Please note that OLM will use ozone data from 2000-2004, which corresponds to the same range of years that was used for the meteorological data.

Note that emissions reduction credits will be obtained by the applicant to offset Project emissions increases of all non-attainment pollutants and their precursors, i.e. $NO_x$, ROG, $PM_{10}$ and $SO_2$ that are above the SJVAPCD offset triggering levels specified in the Districts Rule 2201.4.5.3.

### 4.2.3 Health Risk Assessment Analysis

Both CEC and SJVAPCD require a health risk assessment (HRA) to evaluate potential health effects of TAC emissions from the operation of the project. Contaminants emitted by the project with potential carcinogenic effects or chronic and/or acute non-carcinogenic effects will be considered. This health risk assessment will be performed following the Office of Environmental Health Hazard Assessment (OEHHA), *Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA, 2003)*. As recommended by the *Guidelines*, the California Air Resources Board (CARB) Hotspots Analysis and Reporting Program (HARP) (CARB, 2005) will be used to perform an OEHHA Tier 1 health risk assessment for the project. HARP includes two modules: a dispersion module and a risk module. The HARP dispersion module incorporates the USEPA ISCST3 air dispersion model, and the HARP risk module implements the latest Risk Assessment Guidelines developed by OEHHA. For consistency with the criteria pollutant modeling, the dispersion modeling will be conducted with AERMOD. ARB has created a beta version software package, HARP File Converter, to convert AERMOD dispersion results into a format that can be read into the HARP risk module. Thus HARP with AERMOD will be used for this HRA.

First, ground-level concentrations from HECA emissions will be estimated using the AERMOD dispersion model. The dispersion modeling analysis will be consistent with, and use input parameters that are similar to those discussed above for the criteria pollutant analyses using AERMOD. The same five-year Bakersfield meteorological data set that will be used for the criteria pollutant air quality impact assessment will also be used in the HRA. The maximum 1-hour and annual impacts determined by AERMOD will be used in the HARP model to estimate the corresponding health risks. Receptor spacing will be the same as for the criteria pollutant modeling described later in this Protocol. The HARP simulations will also include the census receptors out to 10 km, and additional receptors will be placed at all sensitive locations (e.g., schools, hospitals, etc.) out to a distance of 5 km (3 miles). Receptors will also be placed at all nearby residents.

Incremental cancer risk will be estimated using the "Derived (Adjusted)" calculation method in HARP. For the calculation of cancer risk, the duration of exposure to project emissions will be assumed to be 24 hours per day, 365 days per year, for 70 years, at all receptors. Chronic non-cancer risks will be calculated by means of the "Derived (OEHHA)" method. No bodies of water are near HECA , thus fish ingestion and drinking water consumption pathways will not be included in this analysis.

The HRA performed by means of the HARP model will follow the following steps:

- Define the location of the maximally exposed individual (MEI) (i.e., the location where the highest carcinogenic risk may occur);
- Define the locations of the maximum chronic non-carcinogenic health effects and the maximum acute health effects;
- Calculate concentrations and health effects at locations of maximum impact for each pollutant; and
- Calculate cancer burden if the maximum cancer risk is predicted to be greater than one in a million.

## 4.3 MODELING EMISSIONS INVENTORY

### 4.3.1 Operational Project Sources

Operational emissions from the project will be dominated by the CTG with HRSG. Conceptual plant design includes SCR for $NO_x$ and oxidation catalysts for CO that will comply with recent BACT determinations for similar IGCC projects recently permitted in United States. Emissions of $SO_2$ and $PM_{10}$ will be maintained at low levels, owing to HECA commitment to have $SO_2$ and $PM_{10}$ emissions comparable to a similarly sized integrated gasification combined cycle power plant having exclusive use of hydrogen as fuel for the gas turbine. Table 4-2 summarizes the estimated annual emissions from the main project sources for each criteria pollutant. The CTG and HRSG emissions estimates reflect the assumed operating hours and numbers of turbine startups described in Section 1.1. Table 4-2 does not include the small contributions to project emissions that will come from the one emergency diesel generator and the one emergency firewater pump engine, or the startup emissions from the thermal oxidizer and the three flares. The engines will normally be operated only a few hours per year in order to test their operability in the event of an emergency situation. The thermal oxidizer and the three flares will have only pilot flame emissions during normal operation. However, non-emergency emissions from these engines, the thermal oxidizer and the three flares will be included in the dispersion modeling conducted for HECA. A more detailed explanation of the sources and their operations including startup will be provided in AFC Section 2: Project Description and Section 5.1: Air Quality and in the Air Quality Appendix C.

**Table 4-2**
**Approximate Annual Pollutant Emissions for HECA Turbine/HRSG, Auxiliary CTG, Auxiliary Boiler, and the Cooling Towers at Steady State Operation**

| Pollutant | Annual Emissions (tpy) | | | | |
|---|---|---|---|---|---|
| | Turbine/HRSG (1) | Auxiliary CTG | Auxiliary Boiler | Cooling Towers(2) | Total HECA Emission Approximation * |
| $NO_x$ | 169 | 17 | 2 | 0 | < 250 |
| CO | 132 | 28 | 6 | 0 | > 250 |
| $SO_2$ | 28 | 2 | 0 | 0 | <50 |
| $PM_{10}$ | 99 | 21 | 0 | 24 | < 250 |
| VOC | 31 | 5 | 1 | 0 | <50 |

Note: * Total HECA emission approximations include bulk materials handling dust emissions and fixed duration events such as startups and shutdown

Note: Auxiliary CTG is used to supply additional peaking power for HECA and for external use.

(1) Total annual HRSG emissions represents the maximum emissions rate from a composite firing scenario (all three fuels)

(2) Includes contributions from all three cooling towers

### 4.3.2 Project Construction Sources

Temporary construction emissions will result from heavy equipment exhaust (primarily $NO_x$ and diesel particulate emissions) and fugitive dust ($PM_{10}$) from earthmoving activities and vehicle traffic on paved and unpaved surfaces. A detailed Excel Workbook will be created to estimate criteria pollutant emissions for non-overlapping phases of Project construction, based on information from the Project design engineers on the equipment use by month throughout the construction schedule and the area extent of ground disturbance that will occur during different construction phases. Depending on the magnitude of emissions for different pollutants and the proximity of construction activities to the property boundary for each phase, one or more emission scenarios representing reasonable worst-case equipment activity and ground disturbance for each averaging time will be selected for subsequent dispersion modeling to ensure that maximum off-site air quality impacts due to these temporary activities will be assessed. The selected emissions scenarios will be modeled using AERMOD with the same near-field receptor grids and the same meteorological input data used for the modeling of the Project's operational emissions. Fugitive dust emissions from the construction site, including the corridors for new transmission lines, gas lines or water pipelines, parking areas and lay-down areas will be modeled as area or volume sources. Equipment exhaust emissions of gaseous pollutants and particulates will be modeled as a series of point sources distributed over the site and linears corridors, as appropriate. Ultra-low sulfur diesel fuel (15 ppm by weight or less) will be utilized on any emission calculations for construction equipment used at HECA site.

### 4.3.3 Toxic Air Contaminant Sources

TACs will also be emitted from the operational HECA project due to combustion of natural gas, hydrogen gas and diesel fuels. Only small quantities of TACs will be emitted from these sources - primarily benzene, formaldehyde, and polycyclic aromatic hydrocarbons, when natural gas will be used as fuel for the CTG/HRSG train and the auxiliary boiler. Two new diesel-fired engines are proposed as part of the project. These include one fire pump engine and two standby emergency generator engine drivers. Emission estimates for TACs from these sources will be based on diesel particulate mater (DPM) emission factors obtained from standard SJVAPCD, CARB and EPA factors and/or vendor data, if available. The cooling towers' TAC emissions will be estimated using cooling tower feedwater quality data and drift calculations. Emissions of TACs from the CTG/HRSG train when hydrogen is being used and from the flares and the tailgas incinerator during periods of startup and shutdown will be estimated using a combination of emission factors, inventories from other IGCC facilities and vendor data, if available.

### 4.3.4 Cumulative Impact Analysis Including Off-Property Sources

A cumulative modeling analyses will be performed using AERMOD to evaluate the combined impacts of HECA Project emissions increases with those of any other new sources within 10 km (6 miles) from HECA that are currently either under construction, undergoing permitting or expected to be permitted in the near future. Requests will be made to the SJVAPCD, Kern County Planning Department, the City of Bakersfield, and adjacent cities to request information that will be used to develop lists of all such new or planned emission sources. When received, these lists will be forwarded to CEC for review. Based on this information, and the CEC response, additional sources may be included in the cumulative source modeling analysis. However, because of the relative remoteness and rural nature of the project site area, few recent new sources are expected to be identified.

## 4.4 BUILDING WAKE EFFECTS

The effect of building wakes (i.e., downwash) upon the stack plumes of emission sources at the facility will be evaluated in accordance with USEPA guidance (USEPA, 1985). Direction-specific building data will be generated for stacks below good engineering practice (GEP) stack height using the most recent version of USEPA Building Parameter Input Program – Prime (BPIP-Prime). Appropriate information will be provided in the AFC and other permit applications that describe the input assumptions and output results from the BPIP-Prime model.

## 4.5 RECEPTOR GRID

The receptor grids that will be used in the AERMOD modeling analyses described in this Protocol for operational sources will be as follows:

- 25-m spacing along the fenceline and extending from the fenceline out to 100 m beyond the property line;
- 50-m spacing from 100 to 250 m beyond the property line;
- 100-m spacing from 250 to 500 m beyond the property line;
- 250-m spacing from 500 m to 1 km beyond the property line;
- 500-m spacing within 1 to 2 km of project sources; and
- 1,000-m spacing within 2 to 10 km of project sources.

During the refined modeling analysis for operational Project emissions, if a maximum predicted concentration for a particular pollutant and averaging time is located within the portion of the receptor grid with spacing greater than 25 m, a supplemental dense receptor grid will be placed around the original maximum concentration point and the model will be rerun. The dense grid will use 25-m spacing and will extend to the next grid point in all directions from the original point of maximum concentration.

Due to the large computation time required to run AERMOD, this receptor grid, with the additional dense nested grid points, was determined to best balance the need to predict maximum pollutant concentrations and allow the all operational modeling runs to be completed in less than one week.

Because construction emission sources release pollutants to the atmosphere from small equipment exhaust stacks or from soil disturbances at ground level, maximum predicted construction impacts for all pollutants and averaging times will occur within the first kilometer from the HECA site boundary. Accordingly, only the portion of the above grid with 25 m spacing out to a distance of 1 km will be used for the construction modeling.

The same receptor grid used in the criteria pollutant modeling for the operational project will be used in the HRA modeling, with additional receptors placed at all sensitive locations (e.g., schools, hospitals, etc.) out to 5 km (3 miles). Census receptors out to 10 km will also be included in the populated areas nearest to the proposed HECA facility. Finally, discrete receptors will be placed at the locations of all nearby residences.

A detailed project map and a 7 ½- minute U.S Geological Survey (USGS) map will be provided in the AFC showing the locations of the grid receptors. Actual Universal Transverse Mercator (UTM) coordinates will be used. The CAAQS and NAAQS apply to all locations outside the applicant’s facility, i.e. everywhere where public access is not under the control of the applicant. Therefore, the fenceline will be placed along the facility’s property boundary, and the receptors will be placed on and outside of the fenceline.

## 4.6 METEOROLOGICAL AND AIR QUALITY DATA

### 4.6.1 Meteorological Data

According to the Guidance for Air Dispersion Modeling – San Joaquin Valley Air Pollution Control District (08/06 Rev 1.2), the SJVAPCD prepared regional meteorological data sets for use in AERMOD. The SJVAPCD expressed that “The availability of standard meteorological data will reduce inconsistencies in data quality and requests to the regulatory agency on obtaining data.” The SJVAPCD used the following meteorological elements in AERMET processing for the 5 year period from 2000 to 2004: ceiling height, wind speed, wind direction, air temperature, total cloud opacity, and total cloud amount. Hourly surface data for calendar years 2000, 2001, 2002, 2003, and 2004 were obtained from the SJVAPCD for the Bakersfield Airport meteorological station which is located, in the City of Bakersfield approximately 32.2 km (20 miles) ENE of the HECA site. Also, these data have been pre-processed by the SJVAPCD with the Oakland upper air data to create an input data set specifically tailored for input to AERMOD.

The "Bakersfield" meteorological data set is available from the SJVAPCD webpage: *http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm*. The guidance describes that the meteorological data provides a standard data set that can be used for air quality studies using AERMOD. The regional data set should not be modified. Therefore, the HECA project site used the SJVAPCD's model-ready AERMET data set.

In addition, the meteorological data recorded at Bakersfield Airport are acceptable for use at HECA facility for two reasons, proximity and terrain similarity. The terrain immediately surrounding the Project site can be categorized as a fairly flat, or gradually sloping rural area in an area with developed oil wells. The terrain around the Bakersfield Airport also consists of relatively flat, or gradually sloping rural or suburban areas. Thus the land use and the location with respect to near-field terrain features are similar. Additionally, there are no significant terrain features separating the Bakersfield Airport from the HECA facility site that would cause significant differences in wind or temperature conditions between these respective areas. Therefore the five years of meteorological data selected from the Bakersfield Airport were determined to be representative for purposes of evaluating the Project's air quality impacts. The Bakersfield Airport is the closest full-time meteorological recording station to the HECA facility site, and thus meteorological conditions at the sites will be very similar.

Seasonal and annual wind roses based on the five years of Bakersfield Airport surface meteorological data are provided as Appendix A to this Protocol. Winds for all seasons and all years blow predominantly from the sector between northwest and north, although the directional pattern is more variable during the fall and winter seasons.

### 4.6.2 Air Quality Monitoring Data

Air quality monitoring data to represent existing air quality in the Project area were obtained from the USEPA AirData (2008) and the CARB-California Air Quality Data website (2008). The most recent three years of data (2006-2008) from the Taft-College, Shafter, Bakersfield Golden State Highway, and Bakersfield 5558 California Avenue monitoring stations were collected to determine the most representative baseline concentrations for each air pollutant and averaging period addressed in the California and National ambient air quality standards. The maximum concentration recorded at these monitoring stations over the three-year period will be used as a conservative representation of existing air quality condition at the proposed Project site. Please note that the background monitoring data from 2006-2008 is used to estimate criteria pollutant impacts using the highest reported values from the most recent three years of available data. This data should not be confused with the ozone data used in the OLM, where the ozone data was obtained from 2000-2004.

The Taft-College monitoring station is located approximately 21 km to the southwest of the HECA facility site. The Taft-College station only monitors $PM_{10}$, and TSP (until 2005). The Bakersfield Golden Highway station monitors all the criteria pollutants, except $SO_2$, and is located approximately 56 km to the southeast of the HECA facility site. The Bakersfield 5558 California Avenue station also measures all pollutants except CO and $SO_2$. This station is located about 30 km east of the HECA site. The only station in the San Joaquin Valley Air Basin that monitors $SO_2$ is the CARB station at First Street in Fresno, located approximately 163 km to the north. $SO_2$ data have only been recorded in Fresno County for the last two years (2007 and 2008), a practice that is justified by the low levels that have been recorded for this pollutant when measurements have been made.

The selected maximum baseline concentrations for all pollutants are summarized in Table 4-3. These data will be added to the modeled maximum impacts due to project emissions for each pollutant and averaging time, and the totals will then be compared with the applicable AAQS. This is a conservative approach because it assumes that the highest recorded background values and the modeled maximum impacts occur at the same time and location for each pollutant and averaging time, a highly unlikely scenario. Note that the maximum background concentrations of $PM_{10}$ and $PM_{2.5}$ in the project area currently exceed the corresponding CAAQS and NAAQS.

**Table 4-3**
**Highest Monitored Pollutant Concentrations Near the Proposed HECA Site (2006 – 2008)**

| Pollutant | Averaging Time | Highest Monitoring Concentration | Monitoring Station Address | Year |
|---|---|---|---|---|
| CO | 8-hour | 2.2 ppm (2,444 $\mu g/m^3$) | Bakersfield Golden State Highway | 2006 |
| | 1-hour | 3.5 ppm (4,025 $\mu g/m^3$) | Bakersfield Golden State Highway | 2008 |
| $NO_2$ | Annual | 0.021 ppm (39.6 $\mu g/m^3$) | Bakersfield Golden State Highway | 2006 |
| | 1-hour | 0.101 ppm (190.1 $\mu g/m^3$) | Shafter-Walker Street | 2007 |
| $SO_2$ | Annual | 0.010 ppm (26.7 $\mu g/m^3$) | Fresno – 1st Street | 2008 |
| | 24-hour | 0.031 ppm (81.38 $\mu g/m^3$)[a] | Fresno – 1st Street | 2007 |
| | 3-hour | 0.075 ppm (195.0 $\mu g/m^3$)[b] | Fresno – 1st Street | 2007 |
| | 1-hour | 0.130 ppm (340.6 $\mu g/m^3$)[b] | Fresno – 1st Street | 2007 |
| $PM_{10}$[c] (Non-attainment area) | Annual | 56.5 $\mu g/m^3$ | Bakersfield Golden State Highway | 2006 |
| | 24-hour | 267.4 $\mu g/m^3$ | Bakersfield Golden State Highway | 2008 |
| $PM_{2.5}$[d] (Non-attainment area) | Annual | 25.2 $\mu g/m^3$ | Bakersfield Golden State Highway | 2007 |
| | 24-hour | 154 $\mu g/m^3$ | Bakersfield Golden State Highway | 2007 |

Source: CARB ADAM website (Last access: February, 2009).

[a.] The highest $SO_2$ monitoring concentration occurred at the Fresno – 1st Street station on July 5, 2007, and was found to be 0.067 ppm. This value was assumed to fall into the category of the EPA Rule 40 CFR 50.14 "Treatment of air quality monitoring data influenced by exceptional events." Because this value occurred on the day after the Independence Day holiday and was twice as high as the next highest monitored 24-hour $SO_2$ value, it was assumed to have been caused by fireworks. Therefore, the concentration on July 5 2007 was not considered for Table 4-3 and the second highest 24-hour value was used instead. Confirmed in an email from Leland Villalvazo on February 4, 2009

[b] It was observed that higher monitoring concentrations were observed at the Fresno -1st Street station on July 4 and July 5, 2007 (the day of and the day after Independence Day). Because these values are much higher than concentrations observed during the rest of the year, they were assumed to have been caused by fireworks. These values will fall into the category EPA Rule 40 CFR 50.14. Therefore, concentrations on July 4 and Jul 5, 2007 were not considered for Table 4-3 and the next highest 1-hour and 3-hour concentrations were used instead. Confirmed in an email from Leland Villalvazo on February 4, 2009

[c] Although EPA has determined that the San Joaquin Valley Air Basin has attained the federal $PM_{10}$ standards, their determination does not constitute a redesignation to attainment per section 107(d)(3) of the Federal Clean Air Act. The Valley will continue to be designated nonattainment until all of the Section 107(d)(3) requirements are met. This area will be treated as the federal $PM_{10}$ non-attainment area until future redesignation.

[d] The Valley is designated nonattainment for the 1997 $PM_{2.5}$ federal standards. EPA designations for the 2006 $PM_{2.5}$ standards will be finalized in December 2009. The District has determined, as of the 2004-06 PM 2.5 data, that the Valley has attained the 1997 24-Hour $PM_{2.5}$ standard. . This area will be treated as the federal $PM_{2.5}$ non-attainment area until future redesignation.

## 4.7 FUMIGATION MODELING

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

A fumigation analysis will be performed using SCREEN3 to calculate concentrations from inversion breakup fumigation; no shoreline fumigation modeling will be performed for the HECA location. A unit emission rate will be used (1 gram per second) in the fumigation modeling simulations to represent the plant emissions, and the model results will be scaled to reflect expected plant emissions for each pollutant. Inversion breakup fumigation concentrations will be calculated for 1- and 3-hour averaging times using USEPA-approved conversion factors. These multiple-hour model predictions are conservative, since inversion breakup fumigation is a transitory condition that would most likely affect a given receptor location for only a few minutes at a time.

# SECTION 5 AIR QUALITY IMPACT ANALYSIS FOR CLASS I AREAS

An evaluation of potential impacts in Class I areas within 100 km of the HECA site will be conducted, because HECA's potential emissions increases of some pollutants will be sufficiently high to be considered a Major Source, thus triggering the federal PSD program. A Major Source must evaluate impacts to visibility and other air quality related values (AQRV) at all Class I areas that are located within a 100-km radius of the facility. All pollutants for which Project emissions are above the Major Source threshold (in this case, 100 tpy) and all pollutants for which emissions are above the PSD Significant Emissions Rates must be evaluated. This section describes the dispersion models and modeling techniques that will be used in performing the Class I area air quality analyses for HECA. The objectives of the modeling are to demonstrate whether air emissions from HECA would 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.

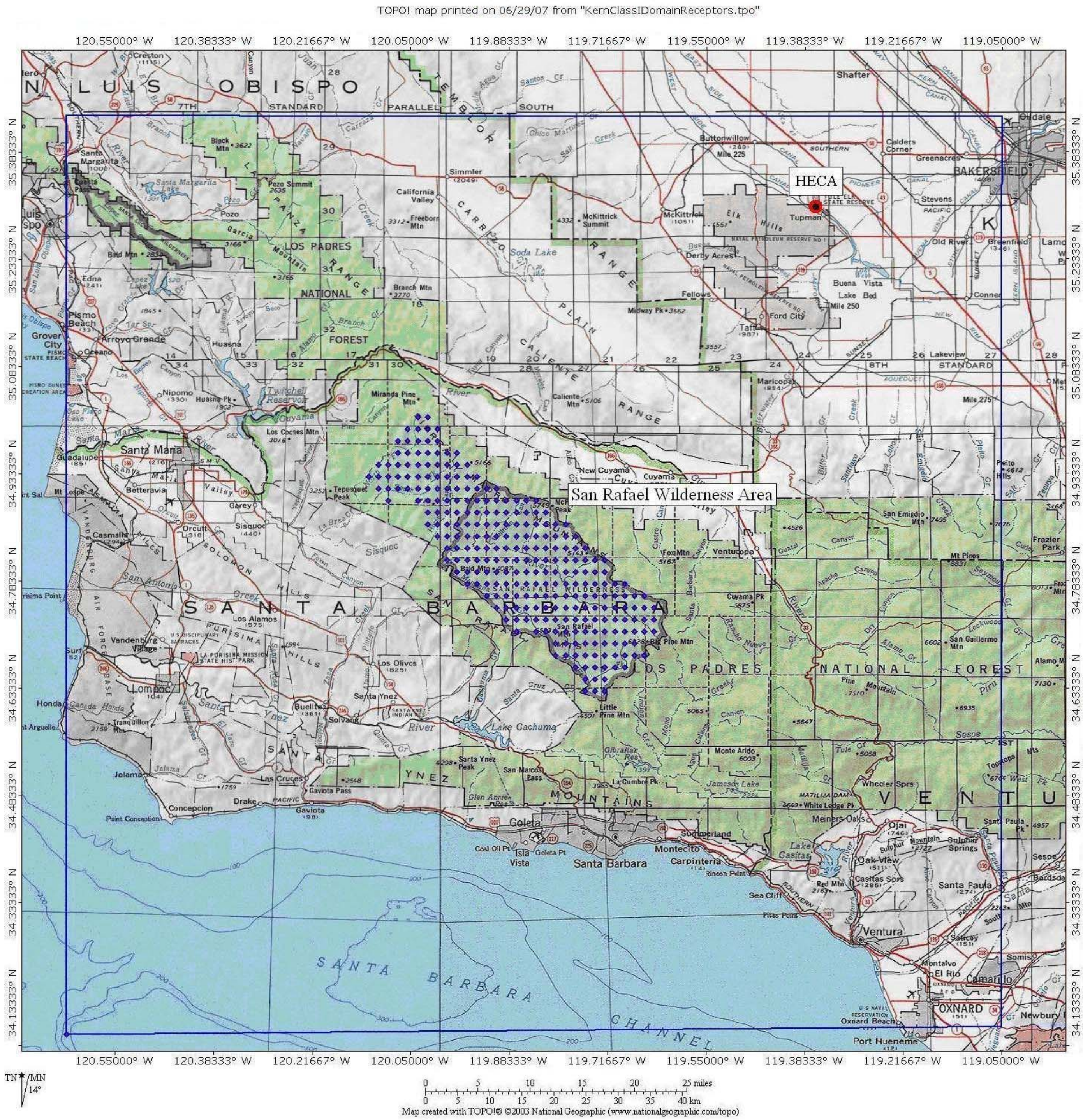
Three Class I areas are located within the region of the HECA site and require further evaluation: Dome Land Wilderness Area, Sequoia National Park, and San Rafael Wilderness Area. However, detailed review of the locations of these Class I areas relative to the HECA site shows that Dome Land Wilderness Area and Sequoia National Park are greater than 100 km from HECA. Therefore, these two Class I areas do not meet the screening criterion of being within 100 km and will not be included in the HECA analysis. NPS has confirmed in comments submitted on a previous version of this document that given the distance and low emissions, they do not believe there will be any significant air quality impacts at Sequoia National Park. The nearest parts of the San Rafael Wilderness are located beyond 50 km and within 100 km from the proposed facility, thus only this Class I area and only far-field AQRV analyses will need to be completed. The CALMET/CALPUFF (full-CALPUFF) model will be used to evaluate potential impacts in the far-field Class I area, including potential air quality impacts, sulfur and nitrogen deposition, and impacts to visibility.

Figure 3 shows the locations of the Class I areas relative to the proposed site for HECA and Table 5-1 lists the distances from HECA to the closest and farthest points in each Class I area. Figure 3 also shows the domain to be used for CALPUFF modeling of the San Rafael Wilderness Area (indicated by the blue rectangle). The federal authority in charge of the two Wilderness Areas is the United States Forest Service (USFS) and the National Park Service (NPS) has jurisdiction in Sequoia National Park. The AQRV analyses for the San Rafael Wilderness area will be conducted in a manner consistent with guidance from the NPS and USFS following the procedures set forth in the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (USFS, 2000) and the Calpuff Reviewer's Guideline (USFS and NPS, 2005).

**Table 5-1**
**Class I Areas Evaluated with Respect to 100-km Radius of the Proposed HECA Facility**

| Class I areas | Distance from HECA (km) | |
|---|---|---|
| Dome Land Wilderness Area | Closest | 110 |
| | Farthest | 132 |
| Sequoia National Park | Closest | 125 |
| | Farthest | 181 |
| San Rafael Wilderness Area | Closest | 62 |
| | Farthest | 81 |

**Figure 4**
**Calpuff Domain and Receptor For the Class I Area Surrounding HECA**



The CALPUFF modeling domain selected for the modeling analyses will extend at least 50 km past the farthest edge in all directions from any of the Class I area being analyzed in order to reduce the probability that mass will be lost due to possible wind recirculation (Figure 3).

## 5.1 NEAR-FIELD CLASS I AREAS AIR QUALITY IMPACT ANALYSIS

There are no Class I Areas within 50 km of the proposed project location; therefore, no near field AQRV analyses are necessary.

## 5.2 FAR-FIELD CLASS I AREA AIR QUALITY IMPACT ANALYSIS: CALPUFF MODELING

To analyze potential impact of project emissions to visibility, PSD increment and sulfur and nitrogen deposition in the Class I area located within 100 km from the proposed project site, the CALPUFF model will be used in conjunction with the CALMET diagnostic meteorological model. CALPUFF is a transport and dispersion model that simulates the advection and dispersion of “puffs” of material emitted from modeled sources. CALPUFF 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 also accept as input; mesoscale meteorological (MM5) data, surface station, 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 simulated. This process results in the generation of gridded 3-dimensional wind fields that account for the effects of slope flows, terrain blocking effects, flow channeling, and spatially varying land uses.

The USEPA-approved regulatory air quality dispersion model CALPUFF (version 5.8) will be used for all far-field Class I area impact analyses. In addition, all supporting Version 5.8 editions of the pre- and post-processors will be used. Recommendations from the regulatory guidance documents listed below will be followed.

- *Federal Land Managers Air Quality Related Values Workgroup (FLAG) Phase 1 Report. (USEPA December 2000),*
- *Interagency Workgroup on Air Quality Modeling (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. (USEPA December 1998)*, and
- *Calpuff Reviewer’s Guide (Draft), (USFS and NPS, 2005).*

Model options will be based on FLM guidance from the above documents and direct discussions with NPS and USFS air quality staff.

Copies of the model input and output files generated in the preparation of this and all other modeling analyses described in this Protocol will be provided with the final application.

### 5.2.1 CALPUFF/CALMET Description

#### *5.2.1.1 Location and Land-Use*

The CALMET and CALPUFF models incorporate assumptions regarding land-use classification, leaf-area index, and surface roughness length to estimate deposition of emitted materials during atmospheric transport. U.S. Geological Survey (USGS) 1:250,000 scale digital elevation models (DEMs) and Land Use Land Cover (LULC) classification files will be used to develop the geophysical input files required by the CALMET model. Outputs of the terrain pre-processor (TERREL) and land use pre-processor (CTGPROC) will be combined in the geo-physical preprocessor (MAKEGEO) to prepare the CALMET geo-physical input file. The CALMET model will incorporate the necessary parameters in the CALMET output files for use in the CALPUFF model.

The CALPUFF modeling domain will extend from the HECA site 150 km to the west, 180 km to the north, 125 km to the east, and 150 km to the south. The grid-cells over this domain will be 4 km wide. The modeling domain will be specified using the Lambert Conformal Conic (LCC) projection system.

#### *5.2.1.2 Meteorological Data*

Pursuant to FLM guidance, a three-year meteorological data set will be developed using a combination of surface station and mesoscale meteorological (MM5) data for 2001-2003. Hourly CALMET data derived from the MM5 data for these three years will be obtained from the WRAP BART modeling for the Nevada-Utah domain. Surface meteorological, precipitation and ozone data will also be obtained from the WRAP BART modeling for the Nevada-Utah domain. No upper air stations will be used, since there are none within the domain shown in Figure 3 and the MM5 data provide a good first approximation of the vertical profile of the atmosphere.

CALMET wind fields will be generated using a combination of the MM5 data sets augmented with the surface data from the National Weather Service (NWS) stations described above. Per IWAQM guidance, the MM5 data will be interpolated to the CALMET fine-scale grid to create the “initial-guess” wind fields (IPROG = 14 for MM5).

#### *5.2.1.3 Other Model Options*

Size parameters for dry deposition of nitrate, sulfate, and $PM_{10}$ particles will be based on default CALPUFF model options. Chemical parameters for gaseous dry deposition and wet scavenging coefficients will be based on default values presented in the CALPUFF User’s Guide. For the CALPUFF runs that incorporate deposition and chemical transformation rates (i.e. deposition and visibility), the full chemistry option of CALPUFF will be activated (MCHEM = 1). The nighttime loss for $SO_2$, $NO_x$ and nitric acid ($HNO_3$) will be set at 0.2 percent per hour, 2 percent per hour and 2 percent per hour, respectively. CALPUFF will also be configured to allow predictions of $SO_2$, sulfate ($SO_4$), $NO_x$, $HNO_3$, nitrate ($NO_3$) and $PM_{10}$ using the MESOPUFF II chemical transformation module.

Hourly ozone concentration files for the CALPUFF modeling will be obtained from the WRAP BART modeling data for the Nevada-Utah domain. Only data from the ozone monitoring stations within the HECA domain will be used.

The background ammonia concentration will be set to 10 ppb, which is representative for a grassland or agricultural site, per the FLAG guidelines.

The regulatory default setting for MDISP=3 which utilizes the Pasquill-Gifford dispersion coefficients will be used in the CALPUFF modeling.

#### *5.2.1.4 Receptors*

Discrete receptors for the CALPUFF modeling within the San Rafael Wilderness Area will be obtained from the NPS Class One Area receptor database. No modifications to the receptor locations or heights provided in the database will be made. Latitude/Longitude coordinates of the Class I receptors will be converted to Lambert Conformal Conic (LCC) coordinates, based on the domain setup shown in CALMET options. These receptor points are shown in Figure 3.

### 5.2.2 Far-Field Class I Area Visibility and Regional Haze Analysis

For the analysis of visibility effects due to emissions of air pollutants, CALPUFF requires project emission rate inputs for six pollutant species, i.e., directly emitted $PM_{10}$, $NO_x$, and $SO_2$, and secondary $SO_4$, $HNO_3$, and $NO_3$. The maximum 24-hour averaged emission rates of $PM_{10}$, $NO_x$ and $SO_2$ from all sources of HECA will be used for the visibility analysis. The turbine/HRSG emissions of $SO_2$ will be specified to $SO_2$ and $SO_4$ as indicated in the NPS Particulate Matter Speciation (PMS) guidelines for gas fired combustion turbines (NPS, 2008). The total turbine/HRSG $PM_{10}$ emissions will be specified to elemental carbon and organic carbon [emitted as Secondary Organic Aerosol (SOA)] per the PMS. Direct emissions of $PM_{10}$, $NO_x$, and $SO_2$ from the auxiliary boiler, emergency generators and fire pump will be modeled without speciation. The cooling towers will emit only $PM_{10}$. Direct emissions of the remaining species, $HNO_3$ and $NO_3$, are assumed to be zero for the natural gas burning sources of HECA.

Modeled impacts will be converted to visibility impacts using the CALPOST post processor. CALPOST will be used to post-process estimated 24-hour averaged concentrations of ammonium nitrate, ammonium sulfate, EC, and SOA into extinction coefficient values for each day at each modeled receptor.

CALPUFF also requires a background light extinction reference level. The analysis will be run using the FLAG recommended background extinction values for the Class I area. The background extinction coefficient is composed of hygroscopic scattering components, wherein the addition of water enhances particle light-scattering efficiencies, non-hygroscopic scattering components and Rayleigh scattering. Ammonium sulfate and ammonium nitrate compose the hygroscopic scattering components, while organic aerosols, soils, coarse particles, particle absorption from elemental carbon and absorption from gases (primarily from nitrogen dioxide) compose the non-hygroscopic scattering components.

In accordance with the FLAG guideline the total background extinction coefficient is calculated for the Class I area using the following equation:

$$b_{ext} = b_{hygro} \cdot f(RH) + b_{non\text{-}hygro} + b_{Ray}$$

where:

$b_{hygro}$ = the hygroscopic scattering component ($Mm^{-1}$)
= $3[(NH_4)_2SO_4 + NH_4NO_3]$
$b_{non\text{-}hygro}$ = the non-hygroscopic scattering component ($Mm^{-1}$)
= $b_{OC} + b_{Soil} + b_{Course} + b_{ap} + b_{ag}$
$b_{Ray}$ = the Rayleigh scattering component ($Mm^{-1}$) = 10 $Mm^{-1}$ (FLAG)
f(RH) = relative humidity adjustment factor

In the CALPOST post-processing program, the monthly background concentration of ammonium sulfate is set to one-third of the hygroscopic scattering component, and the monthly background concentration of soil particles is set to the non-hygroscopic scattering component, as recommended in the FLAG report. The scattering coefficients that will be used in CALPUFF for the Class I areas are presented in Table 5-2.

The FLAG relative humidity (RH) adjustment factors (MVISBK=2) and the RHMAX = 95 % will be used as suggested by the NPS FLM.

The extinction coefficient percent change (background extinction coefficient vs. modeled extinction coefficient), predicted by CALPUFF will be compared to the level of acceptable change (LAC) of 5%. If the change in extinction is greater than 5%, but less than 10%, the conditions surrounding that prediction will be examined to determine if inclement weather may obscure actual viewing of the plume in the Class I area.

**Table 5-2**
**Scattering Coefficients used in CALPUFF Analysis for the San Rafael Wilderness Class I Area**

| Class I Area | Total Background Extinction ($Mm^{-1}$) | | | | Hygroscopic Scattering Component ($Mm^{-1}$) = BKSO4 | Non-hygroscopic Scattering Component ($Mm^{-1}$) = BKSOIL | Rayleigh Scattering ($Mm^{-1}$) |
|---|---|---|---|---|---|---|---|
| | Winter | Spring | Summer | Fall | | | |
| San Rafael Wilderness Area | 16.1 | 16.0 | 16.0 | 16.0 | 0.6 | 4.5 | 10.0 |

### 5.2.3 PSD Class I Significance Analysis

A PSD analysis of incremental air pollutant concentrations in the Class I area due to project emissions will be required, because HECA will be a Major Source as defined in the PSD regulations. Accordingly, the maximum predicted incremental criteria pollutant concentrations from HECA sources in the Class I area will be compared with the Proposed PSD significant impact level for Class I areas (see Table 5-3) for each pollutant.

**Table 5-3**
**FLAG (Proposed) Class I Significance Impact Levels**

| Pollutant and Averaging Time | $NO_x$ | $PM_{10}$ | | $SO_2$ | | |
|---|---|---|---|---|---|---|
| | Annual | 24-hour | Annual | 3-hour | 24-hour | Annual |
| Concentration Threshold (μg/m$^3$) | 0.1 | 0.3 | 0.2 | 1 | 0.2 | 0.1 |

All $NO_2$ and $PM_{10}$, sources of the proposed project will be modeled at the full potential-to-emit (PTE) in the CALPUFF PSD modeling for each averaging time. The facility $SO_2$ emission rate will be portioned into $SO_2$ and $SO_4$ emissions according to the NPS PMS guidance for natural gas combustion turbines. The full chemistry option of CALPUFF will be activated (MCHEM =1, MESOPUFF II scheme), and deposition options will also be turned on (MWET = 1 and MDRY = 1).

### 5.2.4 Deposition Analysis

For the Class I area beyond 50 km from the facility, CALPUFF will be used to evaluate the potential for nitrogen and sulfur deposition due to HECA emissions of nitrogen and sulfur oxides emissions. Total deposition rates for each pollutant will be obtained by summing the modeled wet and/or dry deposition rates. The annual average pollutant emission rates for Project sources will be used in this analysis, since annual deposition rates are to be estimated.

For sulfur deposition, the wet and dry fluxes of sulfur dioxide ($SO_2$) and sulfate ($SO_4$) are calculated, normalized by the molecular weight of sulfur, and expressed as total sulfur. Total nitrogen deposition is the sum of nitrogen contributed by wet and dry fluxes of nitric acid ($HNO_3$), nitrate ($NO_3^-$), ammonium nitrate ($NH_4NO_3$), ammonium sulfate ($(NH_4)_2SO_4$) and the dry flux of $NO_x$.

The total modeled nitrogen and sulfur deposition rates will be compared to the NPS/USFS deposition analysis thresholds (DAT) for western states. The DAT values for nitrogen and sulfur are each 0.005 kilogram per hectare per year (kg/ha-yr), which converts to 1.59E-11 g/m$^2$/s.

### 5.2.5 Soils and Vegetation

The designated Class I area contains vegetative ecosystems that are identified by the Federal Land Managers (FLM) (USFS, 1992). For each ecosystem, sensitive species or groups of species will be designated to represent potential impacts to each vegetative species in the ecosystem. These species are impacted primarily by ozone but may also be impacted by nitrogen and sulfur compounds. Acidity in rain, snow, cloudwater, and dry deposition can affect soil fertility and nutrient cycling processes in watersheds, and can result in acidification of lakes and streams with low buffering capacity. Therefore, the soil and vegetation analysis will be conducted using the CALPUFF model to predict total sulfur and nitrogen deposition rates and monitored ozone concentrations at the nearest air quality monitoring stations. In order to protect sensitive species, the USFS (1992) recommends that short-term maximum $SO_2$ levels should not exceed 40 to 50 parts per billion (ppb). Annual average $SO_2$ concentrations should not exceed 8 to 12 ppb, and annual average $NO_2$ concentration should not exceed 15 ppb.

# SECTION 6 PRESENTATION OF MODELING RESULTS

## 6.1 PSD, NAAQS AND CAAQS ANALYSES

The results of the PSD and AAQS analyses to evaluate the construction and operational impacts of the HECA facility will be presented in summary tables. A figure indicating the locations of the maximum predicted pollutant concentrations for each applicable pollutant and averaging time will be provided. The maximum modeled values of $NO_2$, $SO_2$ and CO will be compared with current Class II and proposed Class I SILs. If the model impact exceeds the SILs, the background concentrations (see Section 4.6.2) will be added to the maximum modeled values from the HECA sources to yield total concentrations, which will be compared with the NAAQS and CAAQS. The cumulative impact values from combination of project sources in HECA and new sources within 10 km (6 miles) of the proposed project site will be added to the background concentrations for the corresponding pollutants and averaging times and will be compared with the NAAQS and CAAQS.

## 6.2 HEALTH RISK ASSESSMENT ANALYSIS

Maps depicting the following data will be prepared:

- Elevated terrain within a 10-km radius of the project;
- The locations of sensitive receptors, including schools, pre-schools, hospitals, etc., within a 5 -km (3 miles) radius of the project, and the nearby residences included in the HRA;
- Isopleths for any areas where predicted exposures to air toxics result in estimated chronic non-cancer impacts and acute impacts equal to or exceeding a hazard index of 1; and
- Isopleths for any areas where exposures to air toxics lead to an estimated carcinogenic risk equal to or greater than one in one million.

Health risk assessment modeling results will be summarized to include maximum annual (chronic, carcinogenic, and non-carcinogenic) and hourly (acute) adverse health effects from HECA's toxic air contaminant emissions. The estimated cancer burden will be presented if the maximum off-site cancer risk is predicted to be greater than one in a million. Health risk values will be calculated and presented in the summary table for the points of maximum impact and the sensitive receptors with the maximum risk values.

## 6.3 CLASS I ANALYSIS

The results of the visibility, PSD and deposition analyses to evaluate the operational impacts of the HECA facility will be presented in summary tables and compared with all relevant significance thresholds. Isopleth drawing showing the predicted spatial distributions of criteria pollutant concentrations in the Class I areas due to the proposed project emissions will also be prepared.

## 6.4 DATA SUBMITTAL

Electronic copies of the modeling input and output files for all the analyses described in this Protocol will be provided to SJVAPCD, CEC and EPA Region IX, U.S. Forest Service and National Park Service.

# SECTION 7 REFERENCES

American Meteorological Society. Journal of Applied Meteorology, 17(5): 636-643. "Correlation of Land Use and Cover with Meteorological Anomalies", August Auer Jr., May 1978.

ARB 2003. HARP User Guide – Software for Emission Inventory Database Management, Air Dispersion Modeling Analyses, and Health Risk Assessment version 1.3, Air Resources, Board, California Environmental Protection Agency. December 2003.

CEC, 1997. "Regulations Pertaining to the Rules of Practice and Procedure and Plant Site Certification". Title 20, California Code of Regulations. Chapter 1, 2, 5.

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National Park Service, 2008. Particulate Matter Speciation: http://www.nature.nps.gov/air/Permits/ect/ectGasFiredCT.cfm

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USDA Forest Service and National Park Service, 2005. CALPUFF Reviewer's Guide (DRAFT) prepared by Howard Gebhart. September 2005

2000-2004 Annual (Jan - Dec)

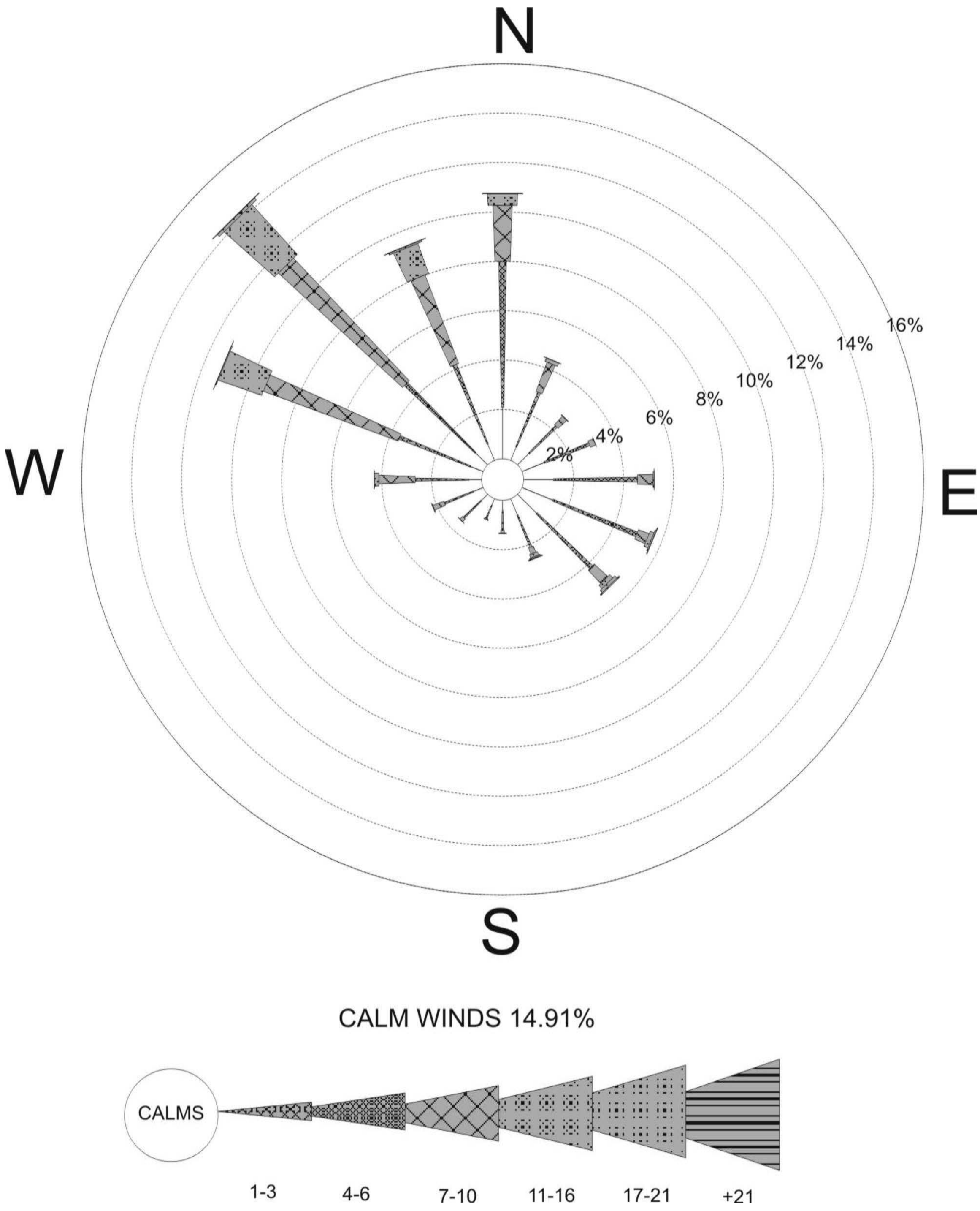


Figure A-1 Annual Windrose for Bakersfield Airport based on Surface Data for 2000-2004

2000-2004 Spring (Mar, Apr, May)

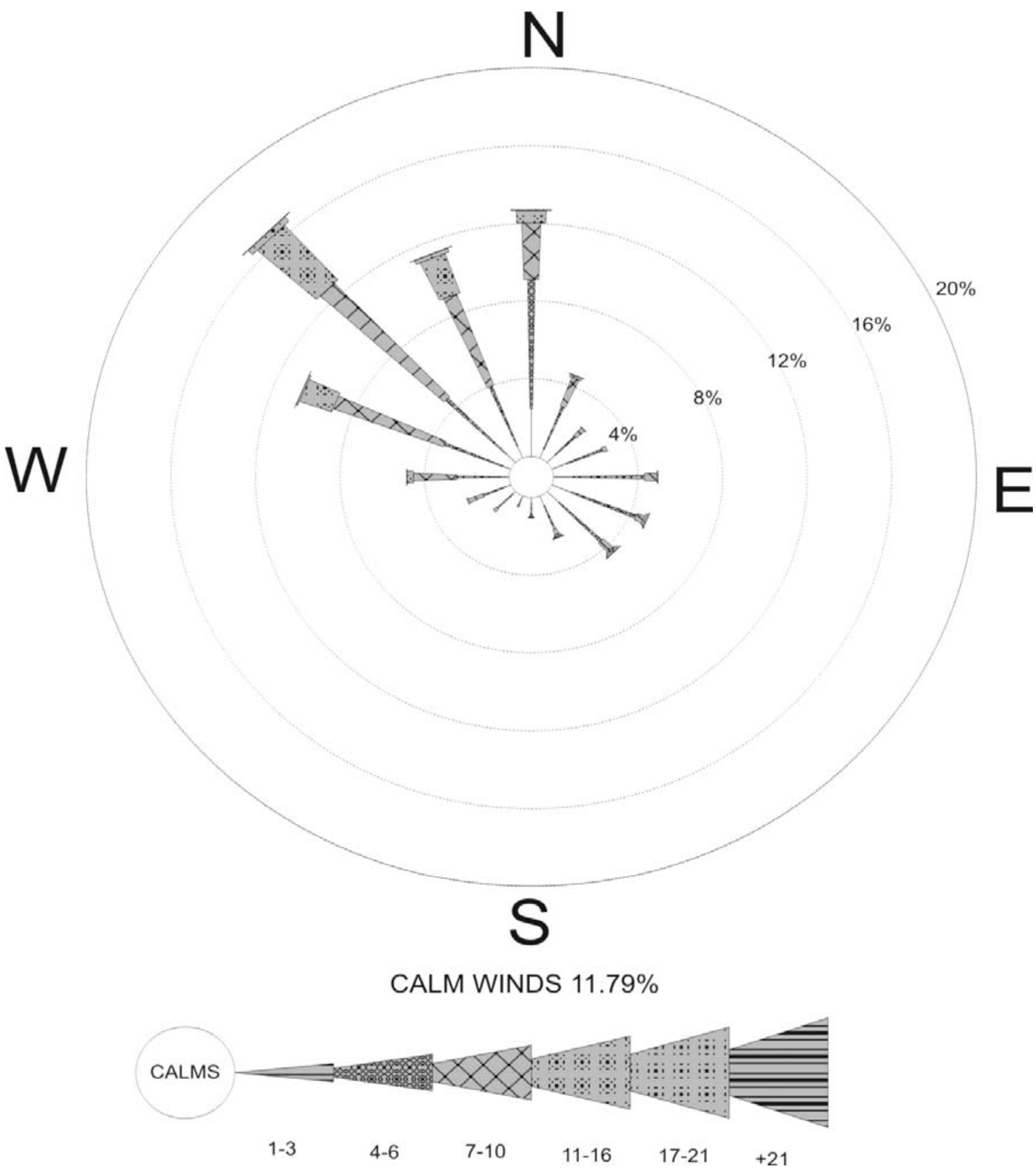


Figure A-2 Spring Season Windrose for Bakersfield Airport based on Surface Data for 2000-2004

2000-2004 Summer (Jun, July, Aug)

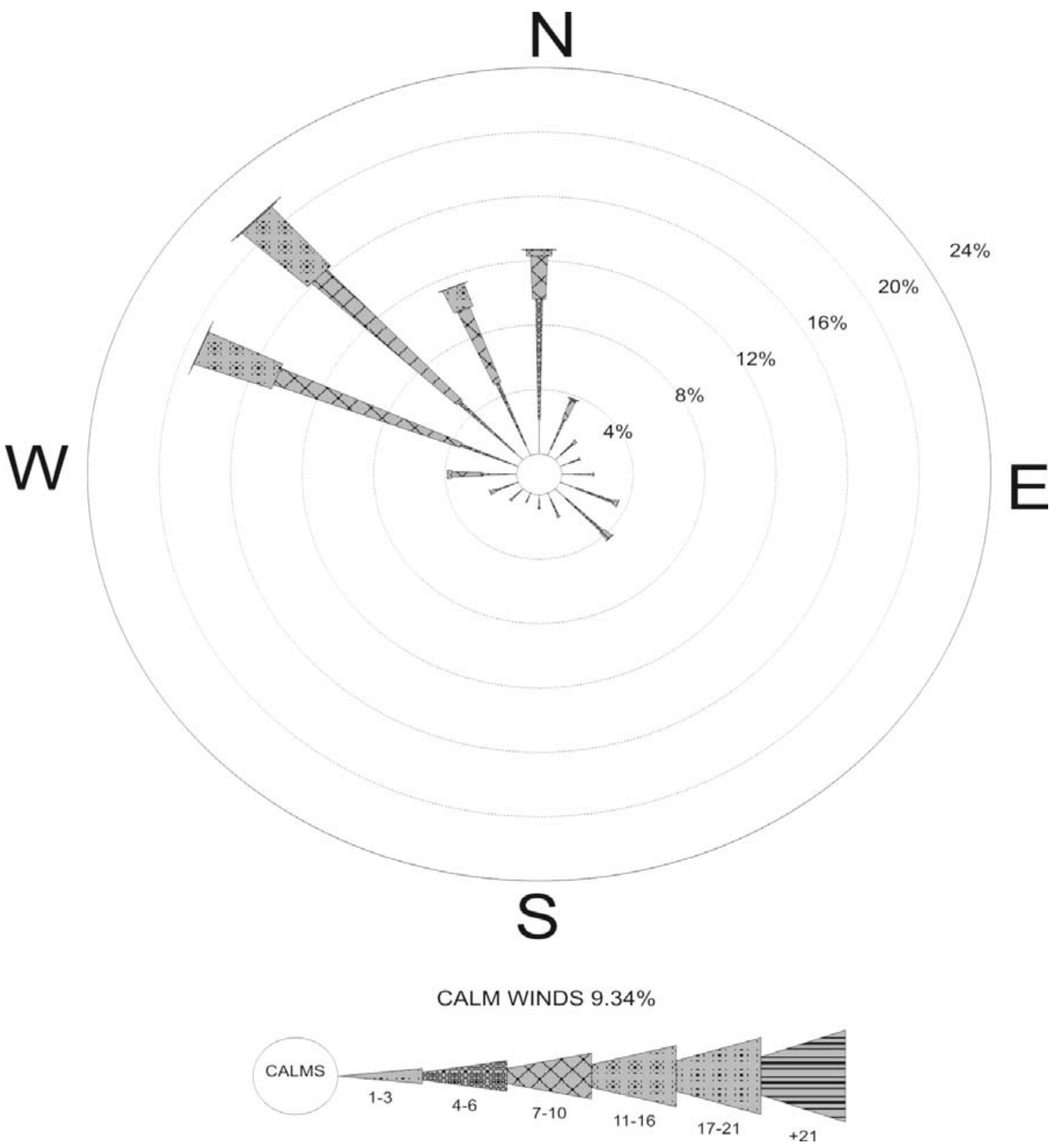


Figure A-3 Summer Season Windrose for Bakersfield Airport based on Surface Data for 2000-2004

2000-2004 Fall (Sep, Oct, Nov)

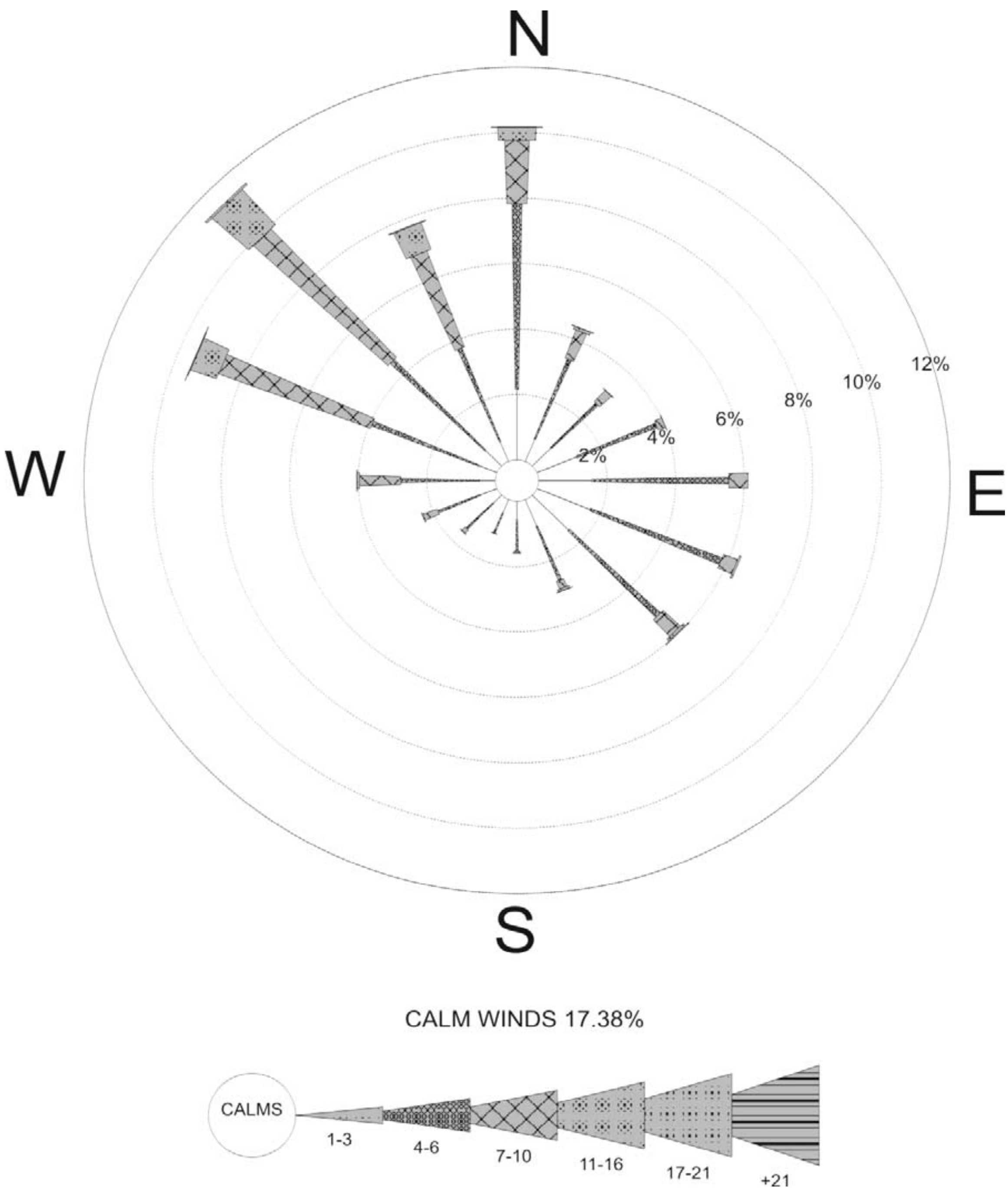


Figure A-4 Fall Season Windrose for Bakersfield Airport based on Surface Data for 2000-2004

2000-2004 (Dec, Jan, Feb)

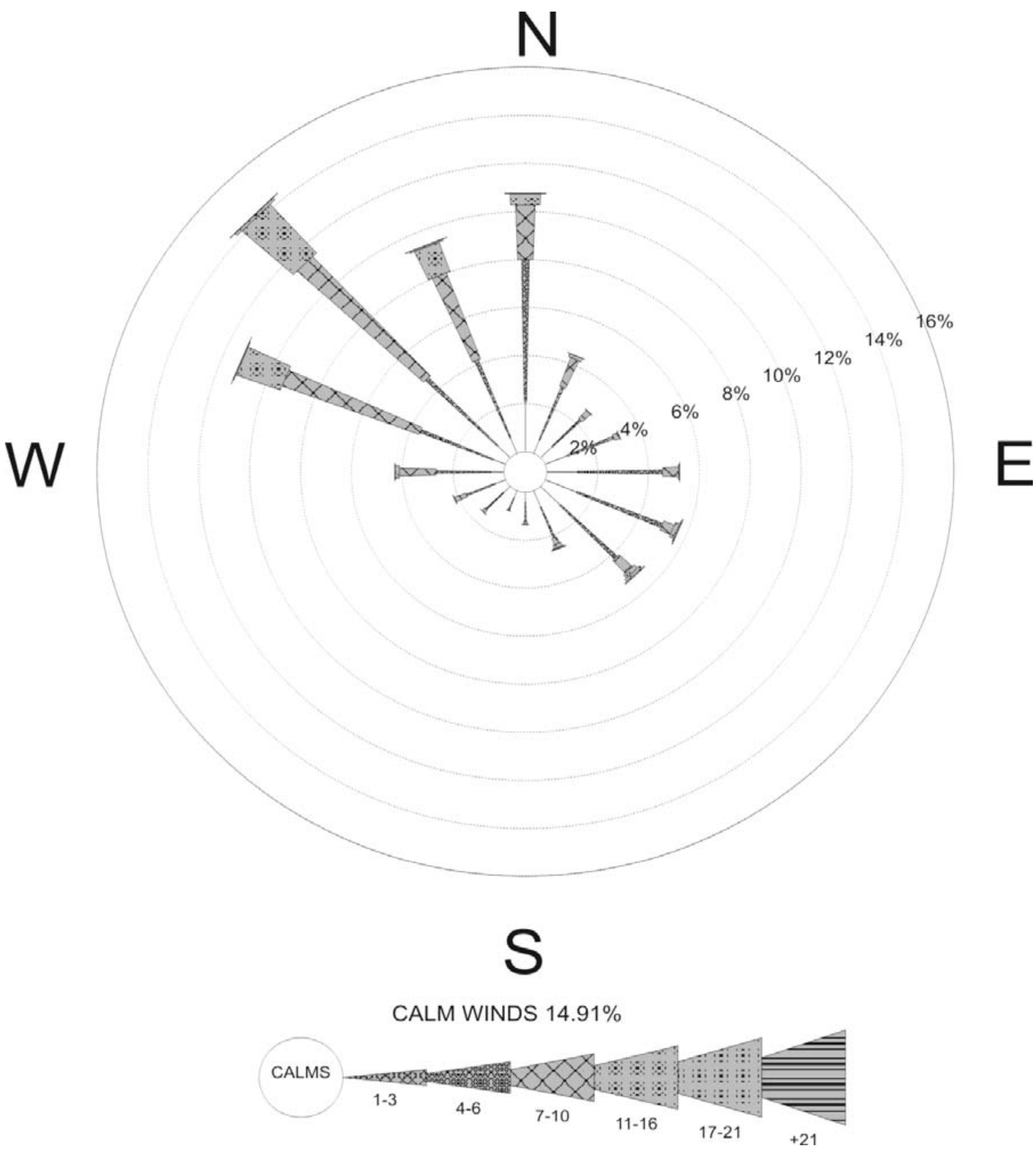


Figure A-5 Winter Season Windrose for Bakersfield Airport based on Surface Data for 2000-2004

**CEC Written Comments on the Modeling Protocol for Hydrogen Energy California Project**

Note: Applicant's Response provided in italic font following comment.

HECA Modeling Protocol Comments

1) Section 4.2.2 Page 4-3. If any of the construction modeling analyses show 1-hour $NO_2$ values greater than 339 $\mu g/m^3$ with the maximum $NO_2$ background added, we request that an hourly $NO_2$ background comparison using 2000-2004 data from the same monitoring site as the ozone data be performed to determine if any hours would still exceed 339 $\mu g/m^3$.

   *Applicant acknowledges this approach but it was not necessary in this case.*

2) Section 4.3.1 – Due to the unusually high fuel delivery/handling requirements for this project, staff requests that operational emission modeling analysis include the dedicated onsite vehicle emissions and onsite fuel haul truck and/or train emissions, and the onsite paved/unpaved road dust.

   *These emissions sources have been included in the modeling analysis.*

3) Section 4.3.1 – The expected flaring and other expected upset/emergency emissions should be modeled to determine worst-case short-term impacts. This section of the protocol should discuss how these potential short-term worst-case events will be included in the operational project sources modeling analysis. Analysis of acute air toxic exposures from these events should also be discussed.

   *Two of the three flares are expected to operate during normal startup and shutdown of the facility and their emissions during these times have been included in the modeling analysis. The third flare is not expected to operate during normal startup and shutdown so there are no emissions from this flare to include in the modeling. There will be no air quality impacts from operations of the flares during "other expected" upset/emergency operations because there are no other expected upset/emergency operations of the flares. Unexpected operation of the flares may occur, but it's too speculative to quantify the nature and frequency of these occurrences in the detail required to provide meaningful input to the model. Impacts to air quality based on speculative input also would be speculative. The approach to modeling the flares is* *therefore consistent with the approach used to model the diesel generator engines and diesel fire water pump engine. Modeling of operations of these diesel engines during, expected, routine testing is included because these are planned operations, emissions from which may be quantified. Modeling of the emergency operations of the engines is not required because the forecast of their emergency operation is too speculative. The flares and the diesel engines are each included in the project as prudent safety measures and to comply with applicable codes and regulations. It is conceivable (and also desirable) that neither the flares nor the diesel engines would operate in an upset/emergency situation during the year.*

4) Section 4.3.1 – A modeling analysis of the CO2 vent should be completed to show it is properly designed to keep potentially harmful CO2 concentrations from impacting facility employees or any offsite receptors. The modeled concentration levels should be compared to appropriate NIOSH and OSHA worker exposure limits and any other relevant sensitive receptor exposure limits.

*The DEGADIS modeling estimated the worst case hourly (D stability and 1 meter per second wind speed) maximum ground level concentrations of CO2 during intermittent CO2 venting to be 6,131 ppm. This value is about 15 percent of the IDLH concentration of 40,000 ppm and less than 20 percent of the NIOSH short-term exposure limit of 30,000 ppm. Therefore it is well below potentially harmful concentrations.*

5) Section 4.3.2 – Please identify the basic source input modeling parameters that will be used for the area, volume, and point sources used for the construction modeling (i.e. initial height, temperature, initial lateral and vertical dimensions, etc. as appropriate for each source type).

*This information has been included in the modeling analysis.*

6) Table 4-3 page 4-11. We believe that footnote "c" in this table is now dated as the final redesignation appears to have been noticed in the Federal Register on November 12th 2008.

*Comment noted. The designation of PM10 under the National Standards is shown in the AFC as "Attainment."*

7) Section 4.7 – Please indicate the emission sources that will be included in the fumigation modeling analysis.

*The sources included in the fumigation model are identified in Section 5.1.2.4.*

Additional Note:

1) In order to try to minimize additional modeling run corrections/requests during project discovery, we would like to point out that several emission sources are inconsistent with other similar equipment staff has experience in licensing, including: a) the PM10 emission rate for the cooling towers is based on a very high TDS content so we suggest reviewing whether such a high TDS is reasonable considering normal TDS limiting issues such as silica content; b) the PM10 emission rate from the LMS100 auxiliary turbine is much higher than any other similar LMS100 project licensed (10.5 lb/hour vs. 6 lb/hour for Panoche and Walnut Creek); c) the PM10 emission rate for the main CTG/HRSG appears high in comparison to other licensed plants on a fuel input basis and 4 ppm for NOx may be too high to meet BACT for a large gas turbine, certainly when operating on natural gas. We suggest a review of these emission sources be performed prior to modeling, because if they are not revised they will certainly be data requests topics.

   *The applicant has revised the BACT emission limit for $PM_{10}$ from the LMS100 auxiliary combustion turbine to 6 lb/hr per the determinations identified above. The cooling tower TDS has not been modified due to the resulting implications on water usage it would create. The CTG/HRSG BACT limit for $NO_x$ when firing natural gas has not been modified due to vendor guarantee limitations. For a complete discussion of the proposed BACT technologies and emission limits see Appendix D-2.*

# Appendix D

# Downwash Parameters

## Downwash Structures

HECA

### Buildings

| | Building Name | Comment | Number of Tiers | Tier Number | Base Elevation (ft) | Tier Height (ft) | Number of Corners | Corner 1 East (X) (m) | Corner 1 North (Y) (m) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | FINESLAG | Fine Slag Handling Enclosure | 1 | 1 | 288.5 | 70 | 4 | 283221.4 | 3912480 |
| 2 | SLRYPREP | Slurry Preparation Building | 1 | 1 | 288.5 | 165 | 4 | 283149.2 | 3912326 |
| 3 | GASIFIER | Gassifier Structure | 1 | 1 | 288.5 | 200 | 4 | 283204 | 3912352 |
| 4 | AGR | AGR Refrigeration Compressor Enclosure | 1 | 1 | 288.5 | 40 | 4 | 283132.3 | 3912194 |
| 5 | CO2 | CO2 Compressor Enclosure | 1 | 1 | 288.5 | 50 | 4 | 283148.9 | 3912117 |
| 6 | ASU_COOL | ASU Cooling Tower | 1 | 1 | 288.5 | 50 | 4 | 282884 | 3912012 |
| 7 | STG | Steam Turbine Generator Structure | 1 | 1 | 288.5 | 50 | 12 | 282851 | 3912173 |
| 8 | CTG | Combustion Turbine Generator | 1 | 1 | 288.5 | 50 | 10 | 282851.4 | 3912218 |
| 9 | AUX_CTG | Auxiliary CTG Structure | 1 | 1 | 288.5 | 45 | 20 | 282856.5 | 3912256 |
| 10 | HRSG | Heat Recovery Steam Generator | 1 | 1 | 288.5 | 90 | 4 | 282934.2 | 3912219 |
| 11 | KO_DRUM | Flare KO Drum | 1 | 1 | 288.5 | 35 | 8 | 283056.8 | 3912304 |
| 12 | PWR_COOL | Power Block and Gassification Cooling To | 1 | 1 | 288.5 | 50 | 4 | 283024.1 | 3912010 |
| 13 | ASU_COMP | ASU Main Air Compressor Enclosure | 1 | 1 | 288.5 | 40 | 4 | 282893.5 | 3912076 |
| 14 | AUX_BOIL | Auxiliary Boiler | 1 | 1 | 288.5 | 50 | 4 | 282913.4 | 3912286 |
| 15 | EMER_GN1 | Emergency Generator - 1 | 1 | 1 | 288.5 | 20 | 4 | 282933.4 | 3912178 |
| 16 | EMER_GN2 | Emergency Generator - 2 | 1 | 1 | 288.5 | 20 | 4 | 282933.3 | 3912169 |
| 17 | AIR_SEP | Air Separation Column Can | 1 | 1 | 288.5 | 85 | 22 | 282918.2 | 3912110 |
| 18 | AGR_METH | AGR Methanol Wash Column | 1 | 1 | 288.5 | 235 | 4 | 283091.7 | 3912224 |
| 19 | LOX_TANK | LOx Tank | 1 | 1 | 288.5 | 90 | 8 | 282870.4 | 3912114 |
| 20 | DEMIN1 | Demineraized Storage Tank 1 | 1 | 1 | 288.5 | 45 | 4 | 282965.9 | 3912234 |
| 21 | DEMIN2 | Demineraized Storage Tank 2 | 1 | 1 | 288.5 | 45 | 4 | 282965.9 | 3912215 |

### Tanks

| | Tank Name | Description | Base Elevation (ft) | Center East (X) (m) | Center North (Y) (m) | Tank Height (ft) | Tank Diameter (ft) |
|---|---|---|---|---|---|---|---|
| 1 | PROC_WTR | Process Water Treatment Feed Tank | 288.5 | 283173.3 | 3912430 | 32 | 35 |
| 2 | GREY_WTR | Grey Water Tank | 288.5 | 283158.5 | 3912415 | 40 | 30 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 3 | SETTLER | Settler | 288.5 | 283184.2 | 3912394 | 35 | 85 |
| 4 | SLURTK_N | Slurry Run Tank - N | 288.5 | 283184 | 3912318 | 75 | 38 |
| 5 | SLURTK_S | Slurry Run Tank - S | 288.5 | 283183.4 | 3912302 | 75 | 38 |
| 6 | SOUR_WTR | Sour Water Stripper Feed Tank | 288.5 | 283022.5 | 3912124 | 32 | 48 |
| 7 | CONDENSA | Condensate Storage Tank | 288.5 | 282957 | 3912250 | 24 | 34 |
| 8 | FIREWATR | Firewater Storage Tank | 288.5 | 282758.5 | 3912510 | 48 | 110 |
| 9 | RAWWATER | Raw Water Tank | 288.5 | 282850.6 | 3912507 | 48 | 100 |
| 10 | TREATD_W | Treated Water Tank | 288.5 | 282857.4 | 3912462 | 40 | 90 |
| 11 | SILO_W | Feedstock Storage Silos -  West | 288.5 | 283261.6 | 3912672 | 150 | 80 |
| 12 | SILO_C | Feedstock Storage Silos - Central | 288.5 | 283290.1 | 3912671 | 150 | 80 |
| 13 | SILO_E | Feedstock Storage Silos - East | 288.5 | 283316.9 | 3912670 | 150 | 80 |
| 14 | METHNL | Methanol Storage Tank | 288.5 | 283115.2 | 3912061 | 40 | 40 |
| 15 | AIR_CAN | Air Separation Can | 288.5 | 282943.5 | 3912107 | 205 | 33 |
| 16 | DEMINERA | Demineraized Storage Tank | 288.5 | 282857.3 | 3912364 | 40 | 60 |
| 17 | PURH2O_1 | Purified Water Tank | 288.5 | 282857.4 | 3912424 | 48 | 90 |
| 18 | PURH2O_2 | Purified Water Tank | 288.5 | 282839.4 | 3912395 | 48 | 42.5 |
| 19 | PURH2O_3 | Purified Water Tank | 288.5 | 282865.6 | 3912396 | 32 | 35 |
| 20 | WATERT_N | Water Treatment Tank North | 288.5 | 282761 | 3912395 | 48 | 120 |

# Appendix E
# Class I Visibility/CALPUFF Analysis

# APPENDIX E

# CALMET/CALPUFF

# AIR QUALITY MODELING IMPACT ANALYSIS FOR FAR-FIELD CLASS I AREAS

# KERN COUNTY, CALIFORNIA

*Prepared For:*

U.S. Environmental Protection Agency Region IX

U.S. Forest Service

*Prepared on behalf of*

**Hydrogen Energy International LLC**

URS

May 2009

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## E1.0 BACKGROUND

In accordance with comments from the National Park Service (NPS), U.S. Forest Service (USFS) and U.S. Environmental Protection Agency (USEPA) Region IX regarding far-field air quality modeling analysis for the proposed Hydrogen Energy California (HECA) project (the Project), a refined CALPUFF modeling analysis was performed in conjunction with the CALMET diagnostic meteorological model. Based on the written comments from the NPS and EPA and verbal comments from the USFS, the refined CALPUFF modeling considered only the San Rafael Wilderness Class I PSD area for the analysis, described in Section 3.0.

## E1.1 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 Work group on Air Quality Modeling (IWAQM) Phase 2 Summary Report. To estimate air quality impacts at distances greater than 50 kilometers, 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 a 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 the following references:

- Federal Land Managers' 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 EPA-approved versions of the CALMET, CALPUFF, CALPOST system (version 5.8, version 5.8 and version 5.6394, respectively) were used.

## E1.2 DOMAIN

For this Project, 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 southwestern corner of the gird cell (1,1) was set to -101 kilometer and -110 kilometer.

At least 50 kilometers of buffer distance was set between the most outer-boundary of all Class I areas within the modeling domain in order to prevent the loss of mass outside the boundary under some meteorological scenarios that might be associated with transport to nearby Class I areas. The total CALMET/CALPUFF modeling domain is shown in Figure 1. The entire MM5 data set domain is shown for information only in Figure 2.

**Figure 1**
**CALMET/CALPUFF Modeling Domain**

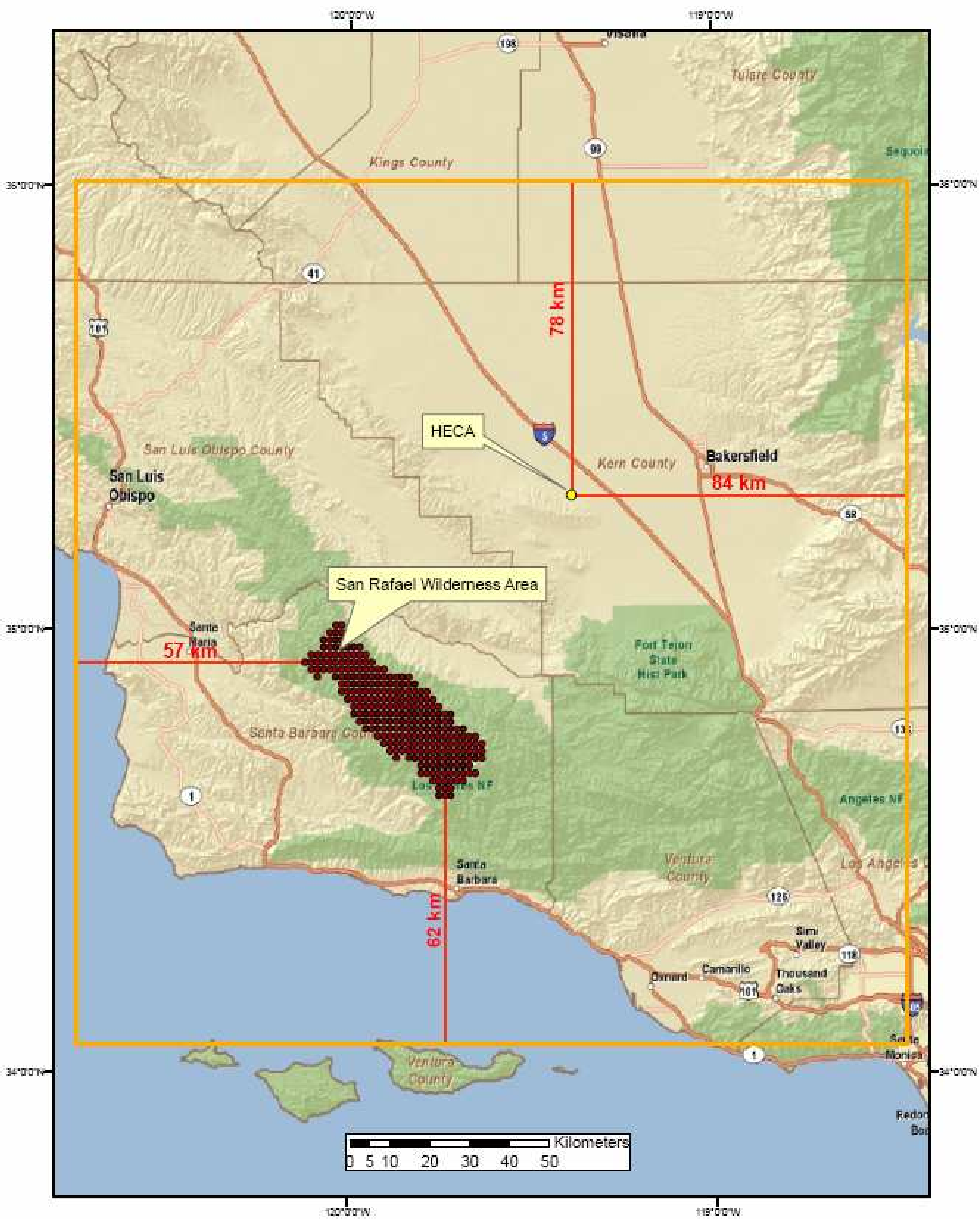



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**Figure 2**
**MM5 and CALMET/CALPUFF Modeling Domain**

# E2.0 CALMET PROCESSING

## E2.1 MM5 DATA

An MM5 data set was used in conjunction with the actual surface and precipitation meteorological data observations. Three years (2001 through 2003) of MM5 data were obtained from Western Regional Air Partnership (WRAP). These 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 kilometer resolution. Initial-guess wind fields based on hourly 36-kilometer MM5 meteorological fields for 2001, 2002 and 2003 (IPROG = 14) were used. MM5 domain is shown in Figure 2.

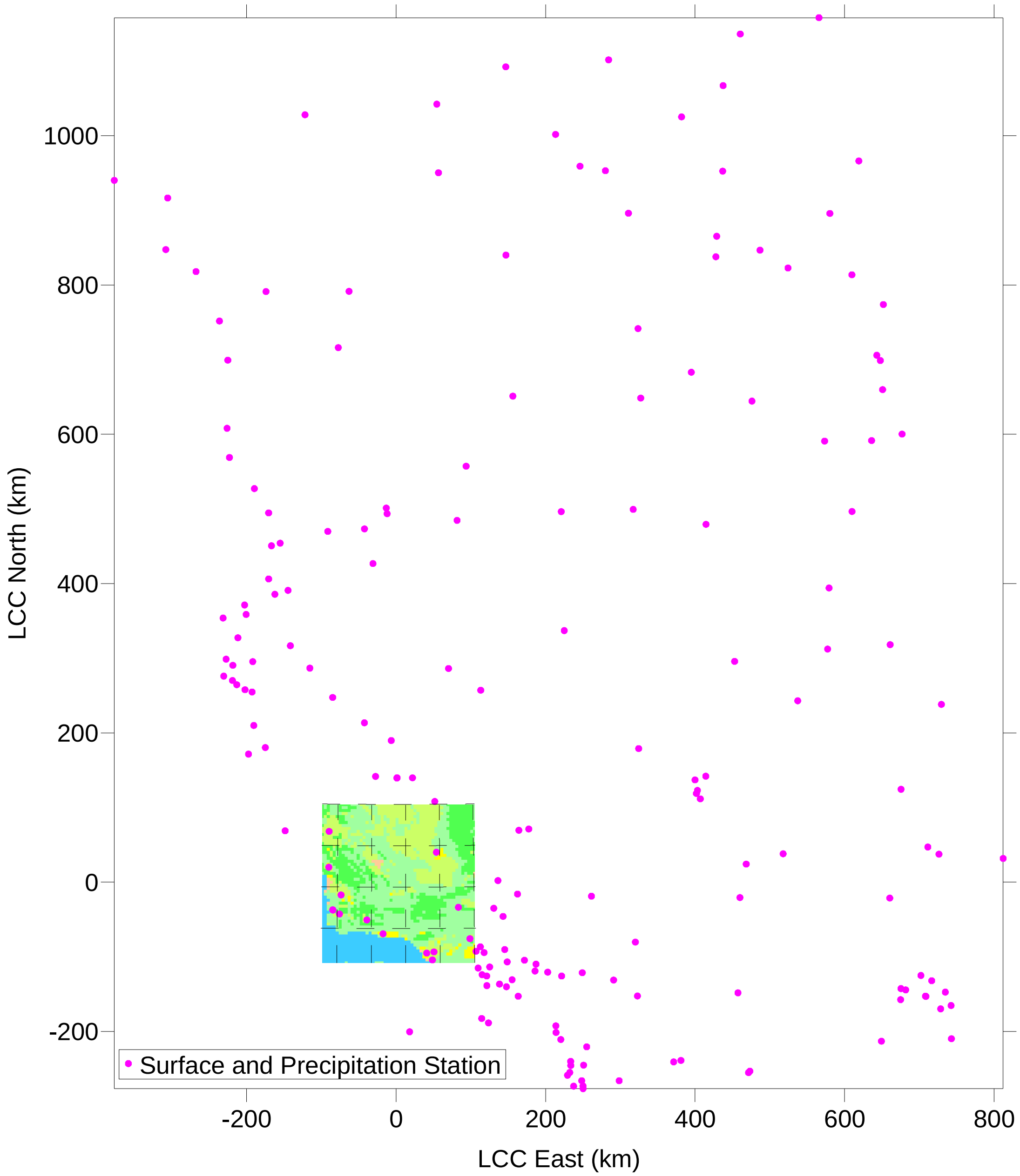
## E2.2 HOURLY SURFACE AND PRECIPITATION DATA

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 a 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 were 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 kilometers.

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

**Figure 3**
**Locations of Surface and Precipitation Data Stations**




## E2.3 UPPER AIR DATA

No observed upper-air meteorological observations were used because they are redundant to the MM5 data and may introduce spurious artifacts in the wind field (WRAP 2006). 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 versus 12-hour) and spatial (36-kilometer versus approximately 300-kilometer) 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 is not needed and in fact will upset the dynamic balance of the meteorological fields potentially producing spurious vertical velocities (WRAP 2006).

## E2.4 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 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-meter above-ground-level CALMET default maximum would occur in the western U.S. (WRAP 2006).

## E2.5 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 the USEPA.

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 kilometers as recommended by the Federal Land Managers. The distance from a surface observation station at which the observations and Step 1 wind field were weighted was set to 50 kilometers, which is within the FLM’s recommended range of 20 to 80 kilometers. Radius of influence for terrain features was set to 10 kilometer. All of these radius-of-influence parameters were set based on CALPUFF Reviewer’s Guide (2005).

## E2.6 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 kilometer 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. 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 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, Los_angeles-w, Montery-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 obtained. After processing, the data were quality checked to ensure land use was accurately represented. USGS land use data contain 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, Montery, 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 4**
**3-D Terrain Elevation Contours**

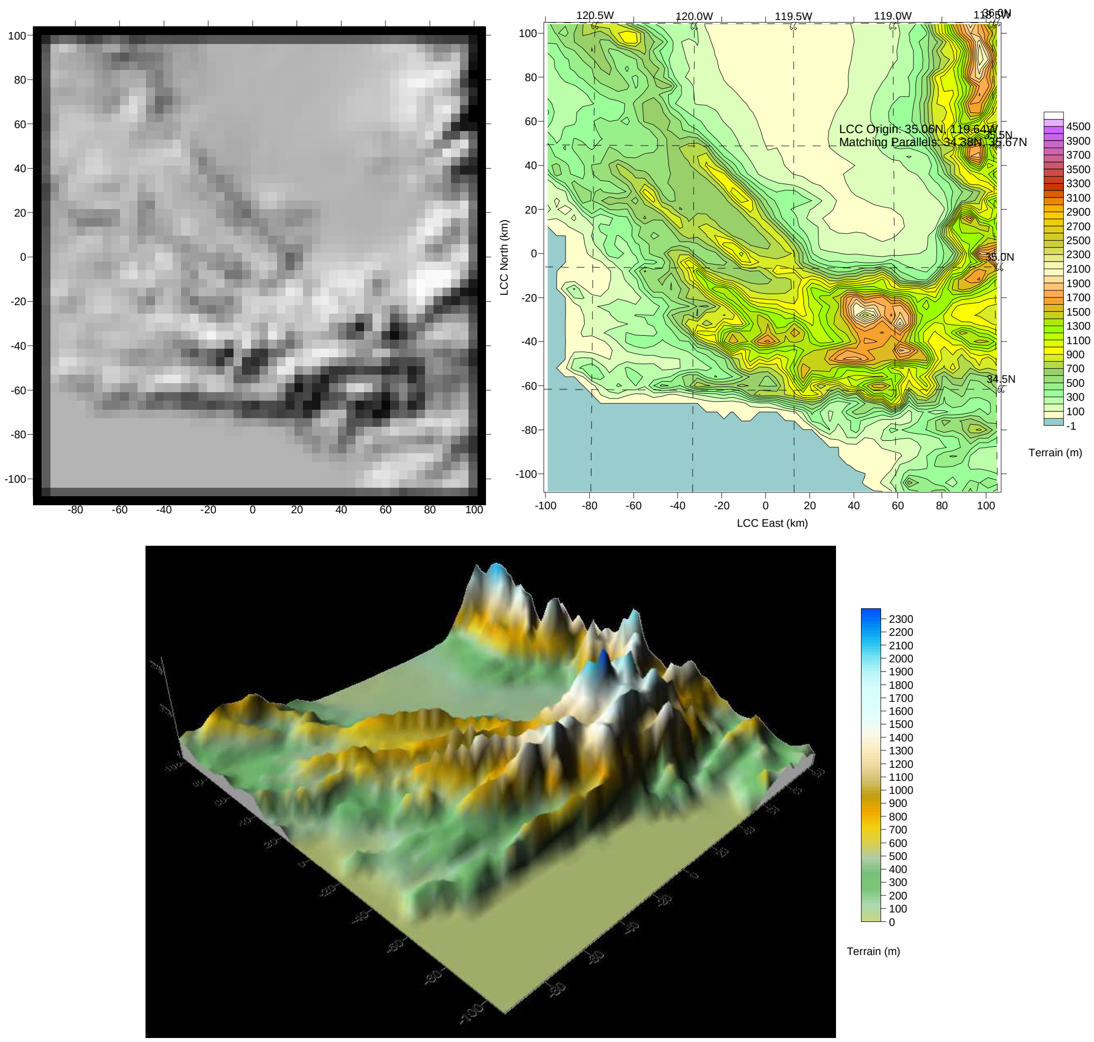
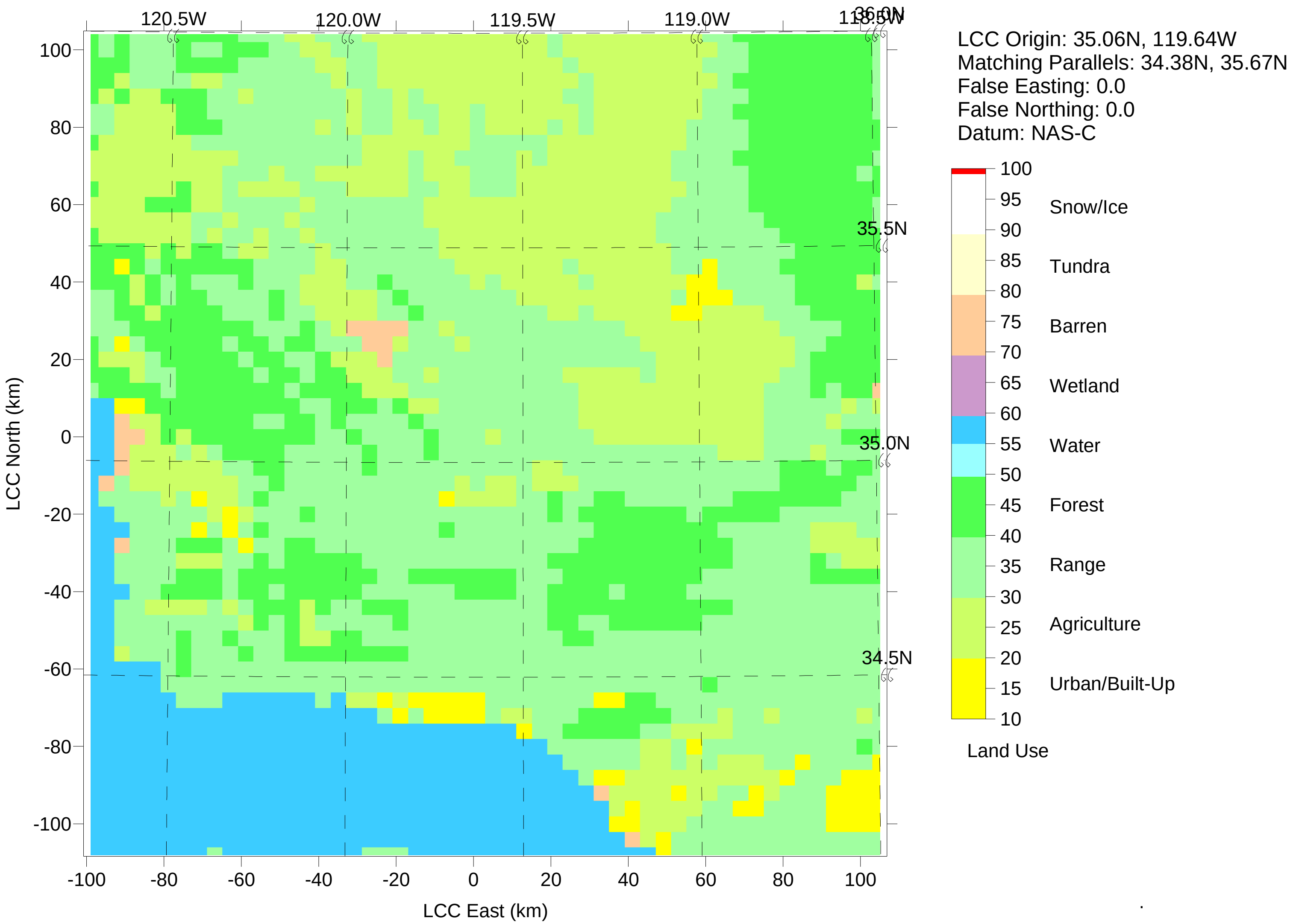


**Figure 5**
**Land Use Land Cover**



# E3.0 CALPUFF PROCESSING

## E3.1 RECEPTORS OF CLASS I AREAS

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

The NPS does not anticipate any significant air quality impact at Sequoia National Park based on the distance (123 kilometers) from the Project facility, and the low emissions from proposed Project facility. Dome Land Wilderness Area is located in the range of 110 kilometers to 169 kilometer distance from the Project Site. Based on the distance, the low emissions from the proposed Project facility, and the dominant wind direction at Bakersfield monitoring station (dominant wind is blowing from the 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 impacts at Dome Land Wilderness Area; therefore, these two Class I areas were not included in the Project analysis. The nearest parts of the San Rafael Wilderness are located beyond 31.1 miles (50 kilometer) and within 62.1 miles (100 kilometer) from the proposed facility; thus, only San Rafael Wilderness Class I area was included in the Air Quality Relative Values (AQRV) analysis.

## E3.2 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 Table 2. The maximum emission rates shown in 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 exempted in the modeling analysis because the auxiliary boiler is not operating when the HRSG turbine is operating). For example, for the 24-hour analysis, it was assumed that the gasification flare operates for 24 hours of wet flaring. This could happen during a cold gasification plant startup, which is anticipated to occur only one time per year and last up to about 26 hours. However, the 24-hour analysis model conservatively assumed that a full 24 hours of this event happens every day, to make sure a worst case scenario was considered. Otherwise, the gasification flare operates on pilot only. In addition, for the 24-hour analysis, the sulfur recovery unit (SRU) flare emissions were estimated assuming 3 hours of startup/shutdown flaring, and the remainder of the day in pilot operation. This startup/shutdown is anticipated to occur only 6 hours total per year; otherwise, the SRU flare operates on pilot only. However, the model conservatively assumed that a full 3 hours of this flaring event happens every day.

Not only was each source above modeled individually using emission rates based on the worst-case scenario, the modeling approach conservatively assumed that cumulatively all the sources will be operated at those emission rates every day. This is a highly improbable operating scenario and results in a very conservative modeling approach. More details of the conservative nature of the modeling approach may be found in Section 4.1 of this appendix.

The stack parameters of all sources are shown in Table 3.

The CALPUFF modeling included speciation of emissions according to the NPS' Particulate Matter Speciation (PMS) method for natural gas combustion turbines. Applying the PMS methodology, 67 percent of total ($SO_2$) start speciated into $SO_2$, and 33 percent of total $SO_2$ were speciated into $SO_4$. Also, the total particulate matter 10 microns in diameter or less ($PM_{10}$) emission from HRSG/Turbine was speciated into Elemental Carbon (EC) and Secondary Organic Aerosol (SOA). The SOA 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). The $PM_{10}$ emissions from other sources were modeled directly as $PM_{10}$. Direct emissions of the remaining species, nitric acid ($HNO_3$) and nitrate ($NO_3$), were assumed to be zero for the natural gas burning sources of the project. The modeled emissions are shown in Table 4 (3-hour averaged), Table 5 (24-hour averaged), and Table 6 (annual averaged). The SOA size distribution is shown in Table 7. In addition, total PM emission was separately modeled as INCPM without speciation for incremental PM analysis.

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.

**Table 2**
**Maximum Emission Rates of Each Averaging Time Period**

| Source | 3-hr (g/s) | 24-hr (g/s) | | | Annual (g/s) | | |
|---|---|---|---|---|---|---|---|
| | $SO_2$ | $NO_x$ | $SO_2$ | $PM_{10}$ | $NO_x$ | $SO_2$ | $PM_{10}$ |
| ASUCOOL1 | - | - | - | 0.0285 | - | - | 0.0271 |
| ASUCOOL2 | - | - | - | 0.0285 | - | - | 0.0271 |
| ASUCOOL3 | - | - | - | 0.0285 | - | - | 0.0271 |
| ASUCOOL4 | - | - | - | 0.0285 | - | - | 0.0271 |
| PWCOOL1 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL2 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL3 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL4 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL5 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL6 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL7 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL8 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL9 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL10 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL11 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL12 | - | - | - | 0.0382 | - | - | 0.0363 |
| PWCOOL13 | - | - | - | 0.0382 | - | - | 0.0363 |
| GASCOOL1 | - | - | - | 0.0300 | - | - | 0.0285 |
| GASCOOL2 | - | - | - | 0.0300 | - | - | 0.0285 |
| GASCOOL3 | - | - | - | 0.0300 | - | - | 0.0285 |
| GASCOOL4 | - | - | - | 0.0300 | - | - | 0.0285 |
| EMERGEN1 [a] | 0.0024 | 0.0324 | 0.0003 | 0.0017 | 0.0022 | 0.00002 | 0.0001 |
| EMERGEN2 [a] | - | - | - | - | - | - | - |
| HRSGSTK | 0.9302 | 6.5718 | 0.9302 | 3.0239 | 4.8092 | 0.8394 | 2.8695 |
| FIREPUMP | 0.0005 | 0.0193 | 0.0001 | 0.0002 | 0.0026 | 0.000008 | 0.000026 |
| AUX_BOIL [b] | - | - | - | - | 0.0492 | 0.0091 | 0.0224 |
| TAIL_TO | 0.2546 | 0.6048 | 0.2546 | 0.0202 | 0.3128 | 0.2521 | 0.0104 |
| $CO_2$_VENT | - | - | - | - | - | - | - |
| SRUFLARE | 2.1933 | 0.0720 | 0.2742 | 0.0018 | 0.0049 | 0.0016 | 0.0001 |
| GF_FLARE | 0.0001 | 7.9380 | 0.0001 | 0.0002 | 0.1239 | 0.0001 | 0.0002 |
| GASVENTA [c] | - | - | - | - | - | - | - |

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

| Source | 3-hr (g/s) | 24-hr (g/s) | | | Annual (g/s) | | |
|---|---|---|---|---|---|---|---|
| | $SO_2$ | $NO_x$ | $SO_2$ | $PM_{10}$ | $NO_x$ | $SO_2$ | $PM_{10}$ |
| GASVENTB [c] | 0.0046 | 0.2495 | 0.0046 | 0.0181 | 0.0513 | 0.0010 | 0.0037 |
| GASVENTC [c] | - | - | - | - | - | - | - |
| AUX_CTG | 0.2343 | 1.1149 | 0.2343 | 0.7560 | 0.5011 | 0.1100 | 0.3547 |
| DC1 | - | - | - | 0.0301 | - | - | 0.0058 |
| DC2 | - | - | - | 0.0761 | - | - | 0.0147 |
| DC3 | - | - | - | 0.0411 | - | - | 0.0363 |
| DC4 | - | - | - | 0.0263 | - | - | 0.0232 |
| DC5 | - | - | - | 0.0252 | - | - | 0.0223 |
| DC6 | - | - | - | 0.0027 | - | - | 0.0004 |
| RC_FLARE | 0.0001 | 0.0045 | 0.0001 | 0.0001 | 0.0045 | 0.0001 | 0.0001 |

Notes:
a. The analysis also assumed that all emissions from two emergency generators are released to the emergency generator 1, which has worst-dispersion characteristics.
b. Auxiliary boiler is not fired at the same time that the HRSG is operating.
c. There are three gasifiers. Only one gasifier warming will be operated at any one time. The emission is from GASVENTB, which results in the worst impact among three gasifiers. $SO_2$ = sulfur dioxide
g/s = grams per second
$NO_x$ = oxides of nitrogen
$PM_{10}$ = particulate matter 10 microns in diameter

**Table 3**
**Source Location and Parameters**

| Source ID | Source Description | UTM Easting (m) | UTM Northing (m) | LCC X (km) | LCC Y (km) | Base Elevation (m) | Stack Height (m) | Stack Temperature (K) | Stack Velocity (m/s) | Stack Diameter (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 | 23.4196 | 30.06494 | 87.93 | 16.76 | 299.9 | 7.98 | 9.14 |
| PWCOOL6 | Power Block Cooling Tower | 283107.9 | 3912000.0 | 23.4354 | 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 | 23.481 | 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 | 30.0669 | 87.93 | 16.76 | 299.9 | 7.98 | 9.14 |
| PWCOOL13 | Power Block Cooling Tower | 283275.2 | 3911998.1 | 23.60261 | 30.068 | 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 | 23.5561 | 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 | 23.5866 | 30.06755 | 87.93 | 16.76 | 299.9 | 7.98 | 9.14 |
| EMERGEN1 | Emergency Generator1 | 282948.3 | 3912172.0 | 23.2713 | 30.23302 | 87.93 | 6.10 | 677.6 | 67.38 | 0.37 |
| EMERGEN2 | Emergency Generator2 | 282948.3 | 3912172.0 | 23.2713 | 30.23302 | 87.93 | 6.10 | 677.6 | 67.38 | 0.37 |
| HRSGSTK | HRSG Stack | 282940 | 3912211.5 | 23.262 | 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 |

**Table 3**
**Source Location and Parameters (Continued)**

| Source ID | Source Description | UTM Easting (m) | UTM Northing (m) | LCC X (km) | LCC Y (km) | Base Elevation (m) | Stack Height (m) | Stack Temperature (K) | Stack Velocity (m/s) | Stack Diameter (m) |
|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 30.1765 | 87.93 | 50.29 | 922.0 | 7.45 | 0.76 |
| $CO_2$_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 | 283212.7 | 3912342.0 | 23.531 | 30.41005 | 87.93 | 64.01 | 338.7 | 26.39 | 0.30 |
| GASVENTB | Gasifier Warming Vent B | 283211.7 | 3912316.6 | 23.53075 | 30.38457 | 87.93 | 64.01 | 338.7 | 26.39 | 0.30 |
| GASVENTC | Gasifier Warming Vent C | 283211.2 | 3912291.0 | 23.53085 | 30.35898 | 87.93 | 64.01 | 338.7 | 26.39 | 0.30 |
| AUX_CTG | AuxiliaryCombustionGasTurbine | 282833.9 | 3912281.9 | 23.15408 | 30.33984 | 87.93 | 33.53 | 677.6 | 15.31 | 4.88 |
| DC1 | FeedStock-DustCollection | 283365.3 | 3913058.7 | 23.6644 | 31.13031 | 87.93 | 13.87 | 291.9 | 15.06 | 0.51 |
| DC2 | FeedStock-DustCollection | 283356.0 | 3912740.9 | 23.66358 | 30.81248 | 87.93 | 51.97 | 291.9 | 14.90 | 0.81 |
| DC3 | FeedStock-DustCollection | 283150.4 | 3912310.2 | 23.46956 | 30.37655 | 87.93 | 53.79 | 291.9 | 14.66 | 0.56 |
| DC4 | FeedStock-DustCollection | 283298.0 | 3912740.9 | 23.60564 | 30.81094 | 87.93 | 51.97 | 291.9 | 15.70 | 0.43 |
| DC5 | FeedStock-DustCollection | 283150.4 | 3912749.0 | 23.45789 | 30.81511 | 87.93 | 24.23 | 291.9 | 15.06 | 0.43 |
| DC6 | FeedStock-DustCollection | 283149.9 | 3912324.5 | 23.46876 | 30.39085 | 87.93 | 53.79 | 291.9 | 14.19 | 0.23 |
| RC_FLARE | Rectisol Flare | 283064.7 | 3912479.1 | 23.3795 | 30.54304 | 87.93 | 76.20 | 1,273 | 20.00 | 0.10 |

**Notes:**
Assumed that the temperature of cooling tower is 8 Kelvin degrees 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 B.
K = Kelvin
km = kilometer
LCC = Lambert Conformal Conic
m = meter
m/s = meters per second
$CO_2$ = carbon dioxide
UTM = Universal Transverse Mercator

**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 | $PM_{10}$ | SOA | | | | | | EC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | PM0005 | PM0010 | PM0015 | PM0020 | PM0025 | PM0100 | |
| EMERGEN1 | 2.35E-03 | - | 3.89E-01 | - | - | 1.69E-03 | 1.69E-03 | - | - | - | - | - | - | - |
| HRSGSTK | 6.20E-01 | 4.65E-01 | 2.10E+01 | - | - | 3.02E+00 | - | 2.70E-01 | 4.51E-01 | 4.15E-01 | 2.70E-01 | 1.98E-01 | 1.98E-01 | 7.56E-01 |
| FIREPUMP | 4.70E-04 | - | 2.32E-01 | - | - | 1.93E-04 | 1.93E-04 | - | - | - | - | - | - | - |
| TAIL_TO | 2.55E-01 | - | 6.05E-01 | - | - | 2.02E-02 | 2.02E-02 | - | - | - | - | - | - | - |
| SRUFLARE | 2.19E+00 | - | 5.44E-01 | - | - | 1.80E-03 | 1.80E-03 | - | - | - | - | - | - | - |
| GF_FLARE | 1.29E-04 | - | 7.94E+00 | - | - | 1.89E-04 | 1.89E-04 | - | - | - | - | - | - | - |
| GASVENTB | 4.63E-03 | - | 2.49E-01 | - | - | 1.81E-02 | 1.81E-02 | - | - | - | - | - | - | - |
| AUX_CTG | 1.56E-01 | 1.17E-01 | 2.60E+00 | - | - | 7.56E-01 | - | 6.75E-02 | 1.12E-01 | 1.03E-01 | 6.75E-02 | 4.95E-02 | 4.95E-02 | 1.89E-01 |
| 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
$PM_{10}$ = particulate matter 10 microns or less in diameter
$SO_2$ = sulfur dioxide
$SO_4$ = sulfate compound
SOA = Secondary Organic Aerosol

**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 | $PM_{10}$ | SOA | | | | | | EC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | PM0005 | PM0010 | PM0015 | PM0020 | PM0025 | PM0100 | |
| ASUCOOL1 | - | - | - | - | - | 2.85E-02 | 2.85E-02 | - | - | - | - | - | - | - |
| ASUCOOL2 | - | - | - | - | - | 2.85E-02 | 2.85E-02 | - | - | - | - | - | - | - |
| ASUCOOL3 | - | - | - | - | - | 2.85E-02 | 2.85E-02 | - | - | - | - | - | - | - |
| ASUCOOL4 | - | - | - | - | - | 2.85E-02 | 2.85E-02 | - | - | - | - | - | - | - |
| PWCOOL1 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL2 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL3 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL4 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL5 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL6 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL7 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL8 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL9 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL10 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL11 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL12 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| PWCOOL13 | - | - | - | - | - | 3.82E-02 | 3.82E-02 | - | - | - | - | - | - | - |
| GASCOOL1 | - | - | - | - | - | 3.00E-02 | 3.00E-02 | - | - | - | - | - | - | - |
| GASCOOL2 | - | - | - | - | - | 3.00E-02 | 3.00E-02 | - | - | - | - | - | - | - |
| GASCOOL3 | - | - | - | - | - | 3.00E-02 | 3.00E-02 | - | - | - | - | - | - | - |
| GASCOOL4 | - | - | - | - | - | 3.00E-02 | 3.00E-02 | - | - | - | - | - | - | - |
| EMERGEN1 | 2.94E-04 | - | 3.24E-02 | - | - | 1.69E-03 | 1.69E-03 | - | - | - | - | - | - | - |
| HRSGSTK | 6.20E-01 | 4.65E-01 | 6.57E+00 | - | - | 3.02E+00 | - | 2.70E-01 | 4.51E-01 | 4.15E-01 | 2.70E-01 | 1.98E-01 | 1.98E-01 | 7.56E-01 |
| FIREPUMP | 5.88E-05 | - | 1.93E-02 | | | 1.93E-04 | 1.93E-04 | | | | | | | |
| TAIL_TO | 2.55E-01 | - | 6.05E-01 | - | - | 2.02E-02 | 2.02E-02 | - | - | - | - | - | - | - |
| SRUFLARE | 2.74E-01 | - | 7.20E-02 | - | - | 1.80E-03 | 1.80E-03 | - | - | - | - | - | - | - |
| GF_FLARE | 1.29E-04 | - | 7.94E+00 | - | - | 1.89E-04 | 1.89E-04 | - | - | - | - | - | - | - |
| GASVENTB | 4.63E-03 | - | 2.49E-01 | - | - | 1.81E-02 | 1.81E-02 | - | - | - | - | - | - | - |
| AUX_CTG | 1.56E-01 | 1.17E-01 | 1.11E+00 | - | - | 7.56E-01 | - | 6.75E-02 | 1.12E-01 | 1.03E-01 | 6.75E-02 | 4.95E-02 | 4.95E-02 | 1.89E-01 |
| DC1 | - | - | - | - | - | 3.01E-02 | 3.01E-02 | - | - | - | - | - | - | - |
| DC2 | - | - | - | - | - | 7.61E-02 | 7.61E-02 | - | - | - | - | - | - | - |
| DC3 | - | - | - | - | - | 4.11E-02 | 4.11E-02 | - | - | - | - | - | - | - |
| DC4 | - | - | - | - | - | 2.63E-02 | 2.63E-02 | - | - | - | - | - | - | - |
| DC5 | - | - | - | - | - | 2.52E-02 | 2.52E-02 | - | - | - | - | - | - | - |
| DC6 | - | - | - | - | - | 2.67E-03 | 2.67E-03 | - | - | - | - | - | - | - |
| 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
$PM_{10}$ = particulate matter 10 microns or less in diameter
$SO_2$ = sulfur dioxide
$SO_4$ = sulfate compound
SOA = Secondary Organic Aerosol

**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 | $PM_{10}$ | SOA | | | | | | EC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | PM0005 | PM0010 | PM0015 | PM0020 | PM0025 | PM0100 | |
| ASUCOOL1 | - | - | - | - | - | 2.71E-02 | 2.71E-02 | - | - | - | - | - | - | - |
| ASUCOOL2 | - | - | - | - | - | 2.71E-02 | 2.71E-02 | - | - | - | - | - | - | - |
| ASUCOOL3 | - | - | - | - | - | 2.71E-02 | 2.71E-02 | - | - | - | - | - | - | - |
| ASUCOOL4 | - | - | - | - | - | 2.71E-02 | 2.71E-02 | - | - | - | - | - | - | - |
| PWCOOL1 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL2 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL3 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL4 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL5 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL6 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL7 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL8 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL9 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL10 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL11 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL12 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| PWCOOL13 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| GASCOOL1 | - | - | - | - | - | 2.85E-02 | 2.85E-02 | - | - | - | - | - | - | - |
| GASCOOL2 | - | - | - | - | - | 2.85E-02 | 2.85E-02 | - | - | - | - | - | - | - |
| GASCOOL3 | - | - | - | - | - | 2.85E-02 | 2.85E-02 | - | - | - | - | - | - | - |
| GASCOOL4 | - | - | - | - | - | 2.85E-02 | 2.85E-02 | - | - | - | - | - | - | - |
| EMERGEN1 | 2.01E-05 | - | 2.22E-03 | - | - | 1.15E-04 | 1.15E-04 | - | - | - | - | - | - | - |
| HRSGSTK | 5.60E-01 | 4.20E-01 | 4.81E+00 | - | - | 2.87E+00 | - | 2.60E-01 | 4.33E-01 | 3.98E-01 | 2.60E-01 | 1.91E-01 | 1.91E-01 | 7.17E-01 |
| FIREPUMP | 8.05E-06 | - | 2.64E-03 | - | - | 2.64E-05 | 2.64E-05 | - | - | - | - | - | - | - |
| AUX_BOIL | 9.13E-03 | - | 4.92E-02 | - | - | 2.24E-02 | 2.24E-02 | - | - | - | - | - | - | - |
| TAIL_TO | 2.52E-01 | - | 3.13E-01 | - | - | 1.04E-02 | 1.04E-02 | - | - | - | - | - | - | - |
| SRUFLARE | 1.58E-03 | - | 4.91E-03 | - | - | 1.23E-04 | 1.23E-04 | - | - | - | - | - | - | - |
| GF_FLARE | 1.29E-04 | - | 1.24E-01 | - | - | 1.89E-04 | 1.89E-04 | - | - | - | - | - | - | - |
| GASVENTB | 9.51E-04 | - | 5.13E-02 | - | - | 3.73E-03 | 3.73E-03 | - | - | - | - | - | - | - |
| AUX_CTG | 7.33E-02 | 5.50E-02 | 5.01E-01 | - | - | 3.55E-01 | - | 3.17E-02 | 5.28E-02 | 4.85E-02 | 3.17E-02 | 2.32E-02 | 2.32E-02 | 8.87E-02 |
| DC1 | - | - | - | - | - | 5.82E-03 | 5.82E-03 | - | - | - | - | - | - | - |
| DC2 | - | - | - | - | - | 1.47E-02 | 1.47E-02 | - | - | - | - | - | - | - |

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

| Sources (g/s) | $SO_2$ | $SO_4$ | $NO_x$ | $HNO_3$ | $NO_3$ | INCPM | $PM_{10}$ | SOA | | | | | | EC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | PM0005 | PM0010 | PM0015 | PM0020 | PM0025 | PM0100 | |
| DC3 | - | - | - | - | - | 3.63E-02 | 3.63E-02 | - | - | - | - | - | - | - |
| DC4 | - | - | - | - | - | 2.32E-02 | 2.32E-02 | - | - | - | - | - | - | - |
| DC5 | - | - | - | - | - | 2.23E-02 | 2.23E-02 | - | - | - | - | - | - | - |
| DC6 | - | - | - | - | - | 4.00E-04 | 4.00E-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
$PM_{10}$ = particulate matter 10 microns or less in diameter
$SO_2$ = sulfur dioxide
$SO_4$ = sulfate compound
SOA = Secondary Organic Aerosol

**Table 7**
**Size Distribution of SOA**
**(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
SOA = Secondary Organic Aerosol

## E3.3 CALPUFF PARAMETERS

The CALPUFF options were selected to follow the EPA's recommended settings for regulatory modeling or WRAP's BART modeling.

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 the hourly ozone concentration file was set to 80 parts per billion (ppb). The monthly background ammonia concentration was set to 10 ppb.

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.

## E3.4 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. 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 rates were modeled for 3-hour $SO_2$ increment analysis. Emissions of total $SO_2$ from the natural gas combustion turbines was speciated based on the 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.

## E3.5 CLASS I AREA VISIBILITY REDUCTION ANALYSIS

Refined CALPUFF was used to evaluate the potential for visibility reduction. All sources were modeled at the full PTE for this analysis. Emissions of total $SO_2$ and $PM_{10}$ from the natural gas combustion turbines were speciated based on NPS' PMS guideline as described.

The emissions of thirteen chemical species, $SO_2$, $SO_4$, $NO_x$, $HNO_3$, $NO_3$, $PM_{0.05}$, $PM_{0.01}$, $PM_{0.15}$, $PM_{0.20}$, $PM_{0.25}$, $PM_{1.0}$, EC, and $PM_{10}$, 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 HRSG and Turbine, the total $PM_{10}$ emissions were speciated into EC and SOA. The SOA 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 $PM_{10}$ emissions were modeled as $PM_{10}$ without speciation.

CALPOST was used to post-process the estimated 24-hour averaged ammonium nitrate, ammonium sulfate, elemental carbon, SOA, and $PM_{10}$ concentrations into an extinction coefficient value for each day at each modeled receptor, using the 3 years of CALMET meteorological data. To do so 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 SOA. Default extinction efficiencies of $PM_{10}$ (Coarse Particulate), SOA, EC, soil, ammonium sulfate, and ammonium nitrate were used.

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 micrograms per cubic meter [$\mu g/m^3$]) and the non-hygroscopic concentration (4.5 $\mu g/m^3$) are reported for the 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.

## E3.6 TOTAL NITROGEN AND SULFUR DEPOSITION ANALYSIS

Refined CALPUFF was used to evaluate the potential for nitrogen and sulfur deposition. 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' 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 $NO_x$.

The total modeled nitrogen and sulfur deposition rates were compared to the NPSUSFWS 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 $g/m^2/s$.

# E4.0 MODELING RESULTS

## E4.1 CALPUFF MODELING RESULTS

Three years of CALPUFF modeling results are provided in Tables 8 through 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 modeled number of days that exceeds 5 percent of extinction change is 2 days for 2001 and 2003, and 4 days for 2002.

The visibility modeling analysis was performed based on emission rates corresponding to the following very conservative operating scenario:

- It was assumed that the gasification flare operates for the full 24 hours using the wet flaring emission rate. This could happen in a cold gasification plant startup, and is anticipated to occur only one time per year and last up to about 26 hours. Otherwise, the gasification flare operates on pilot only. $NO_x$ emissions from wet flaring are about 1,000 times greater than pilot operation and make the gasification flare during wet flaring the largest source of $NO_x$ on the site. However, the 24 hour analysis model conservatively assumed that a full 24 hours of this event happens every day, a worst case scenario.

- SRU flare emissions for the 24-hour period were estimated assuming 3 hours of startup/shutdown flaring and the remainder of the day in pilot operation. This startup/shutdown is anticipated to occur only 6 hours total per year; otherwise, the SRU flare operates on pilot only. However, the model conservatively assumed that a full 3 hours of this flaring event happens every day.

- The Emergency generator and firewater pump will be operated for 50 hours per year and 100 hours per year, respectively. However, the model conservatively assumed that a full 24 hours of this event happens every day.

- HRSG $NO_x$ emissions were estimated based on 1 cold startup and one hot startup, and the balance of the day at full load using natural gas for a 24 hour period. The model conservatively assumed that a full 24 hours of this event happens every day.

Not only was each source above modeled individually using emission rates based on the worst-case scenario, the modeling approach conservatively assumed that cumulatively all the sources will be operated at those emission rates every day. Based on this very conservative modeling approach, 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 conservative operating scenario; therefore, the proposed Project sources will not have a significant impact on the ambient air quality of the San Rafael Wilderness Class I area. Because 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 on aquatic resources. Therefore, no further analyses were conducted, including additional AQRV impacts.

## 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/m$^3$** | **µg/m$^3$** | **µg/m$^3$** | **µg/m$^3$** | **µg/m$^3$** | **Annual** |
| | **Threshold** | **0.1** | **1** | **0.2** | **0.08** | **0.32** | **0.16** |
| San Rafael Wilderness Area | 2001 | 4.09E-03 | 2.23E-01 | 2.78E-02 | 8.06E-04 | 1.14E-01 | 4.17E-03 |
| | 2002 | 4.48E-03 | 2.43E-01 | 2.98E-02 | 9.54E-04 | 1.09E-01 | 4.76E-03 |
| | 2003 | 4.62E-03 | 2.84E-01 | 3.05E-02 | 9.54E-04 | 1.23E-01 | 4.68E-03 |
| Exceed? | | No | No | No | No | No | No |

Notes:
µg/m$^3$ = 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

## 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** | **%** | **Day** |
| | **Threshold** | **0** | **0** | **10** | |
| San Rafael Wilderness Area | 2001 | 2 | 0 | 9.64 | 308 |
| | 2002 | 4 | 0 | 8.09 | 287 |
| | 2003 | 2 | 0 | 6.58 | 247 |
| Exceed? | | | | No | |

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

| Class I Area | Pollutant | Deposition N | Deposition S |
|---|---|---|---|
| | **Unit** | **g/m$^2$/s** | **g/m$^2$/s** |
| | **Threshold** | **1.59E-11** | **1.59E-11** |
| San Rafael Wilderness Area | 2001 | 1.04E-12 | 4.23E-13 |
| | 2002 | 1.30E-12 | 5.57E-13 |
| | 2003 | 1.32E-12 | 4.97E-13 |
| Exceed? | | No | No |

## E5.0 REFERENCES

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