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5.1 AIR QUALITY

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 an Integrated Gasification Combined Cycle power generating facility called Hydrogen Energy California (HECA or Project) in Kern County, California. The Project will produce low-carbon baseload electricity by capturing carbon dioxide (CO_2) and transporting it for CO_2 enhanced oil recovery (EOR) and sequestration (storage)[1].

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 2-1, Project Vicinity. HEI is also acquiring an additional 628 acres of land adjacent to the Project Site, herein referred to as "Controlled Area" (see Figure 2-4, Site Plan). 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 a hydrocarbon-producing area known as the Elk Hills Field. The Project Site is currently used primarily for agricultural purposes. Existing surface elevations vary from about 282 feet to 291 feet above mean sea level.

The Project will gasify petroleum coke (petcoke) (or blends of petcoke and coal, as needed) to produce hydrogen to fuel a combustion turbine operating in combined cycle mode. The Gasification Block feeds a 390-gross-megawatt (MW) combined-cycle plant. The net electrical generation output from the Project will provide California with approximately 250 MW of low-carbon baseload power to the grid. The Gasification Block will also capture approximately 90 percent of the carbon from the raw 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 Project Site and linear facilities comprise the affected study area and are entirely located in Kern County, California. These Project components are described below.

Major on-site Project components will include, as shown on Figure 2-5, Preliminary Plot Plan:

- Solids Handling, Gasification, and Gas Treatment
  - Feedstock delivery, handling and storage
  - Gasification
  - Sour shift/gas cooling
  - Mercury removal
  - Acid gas removal

[1] This carbon dioxide will be compressed and transported via pipeline to the custody transfer point at the adjacent Elk Hills Field, where it will be injected. The CO_2 EOR process involves the injection and reinjection of carbon dioxide to reduce the viscosity and enhance other properties of the trapped oil, thus allowing it to flow through the reservoir and improve extraction. During the process, the injected carbon dioxide becomes sequestered in a secure geologic formation. This process is referred to herein as CO_2 EOR and Sequestration.

- Power Generation
  - Combined-cycle power generation
  - Auxiliary combustion turbine generator
  - Electrical switching facilities

- Supporting Process Systems
  - Natural gas fuel systems
  - Air separation unit (ASU)
  - Sulfur recovery unit/Tail Gas Treating Unit
  - Zero liquid discharge (ZLD) units for process and plant waste water streams
  - Carbon dioxide compression
  - Raw water treatment plant
  - Other plant systems

The Project also includes the following offsite facilities, as shown on Figure 2-7, 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; each alternative is approximately 8 miles in length.

- **Natural Gas Supply** – A natural gas interconnection will be made with PG&E or SoCalGas natural gas pipelines, each of which are located southeast of the Project Site. The natural gas pipeline will be approximately 8 miles in length.

- **Water Supply Pipelines** – The Project will use brackish groundwater supplied from the Buena Vista Water Storage District (BVWSD) 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 will be 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 alternative will be approximately 4 miles in length.

The Project components described above are shown on Figure 2-8, Project Location Details, which depicts the region, the vicinity, the Project Site and its immediate surroundings.

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 5.1-1, Project Disturbed Acreage.

Table 5.1-1
Project Disturbed Acreage

Project Component	Size	Approx. Linear Length (miles)	ROW Construction	ROW Permanent	Temporary Disturbance (acres)	Permanent Disturbance (acres)
Project Site	473 acres	NA	NA	NA	473	250
Electrical transmission line	25-foot-diameter structural base (60 structures total)	8	175 feet[1]	150 feet	24	0.67[2]
Natural gas pipeline	16-inch diameter	8	50 feet	25 feet	50[3]	0.33[4]
Process water pipeline	20-inch diameter	15	50 feet	25 feet	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 feet	25 feet	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
NA = not applicable
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) a 150-foot by 150-foot 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/exist 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-foot by 150-foot temporarily disturbed area required for the construction of each of five groundwater wells.
6. Acreage includes the 50-foot by 50-foot permanent disturbed area required for each of five groundwater wells.
7. Acreage includes two 50-foot by 50-foot valve boxes positioned along the pipeline route.

This analysis of the potential air quality impacts of the Project was conducted according to California Energy Commission (CEC) power plant siting requirements. It also addresses U.S. Environmental Protection Agency (USEPA) Prevention of Significant Deterioration (PSD) requirements and San Joaquin Valley Air Pollution Control District (SJVAPCD) permitting requirements for Determination of Compliance/Authority to Construct (DOC/ATC). The analysis is reported as follows:

- Section 5.1.1, Affected Environment, describes the local environment surrounding the Project Site. Meteorological data, including wind speed and direction (i.e., wind roses), temperature, relative humidity, and precipitation are discussed, and ambient concentrations for the appropriate criteria pollutants are summarized.

- Section 5.1.2, Environmental Consequences, evaluates the Project's air quality impacts from emissions of nitrogen oxide (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). Emission estimates are presented for these pollutants for Project construction and operation over a range of operating modes, including startup and shutdown. The modeling analysis conducted for nitrogen dioxide (NO_2), CO, SO_2, $PM_{2.5,}$ and PM_{10} is presented; the results show no exceedances of the state and federal Ambient Air Quality Standards (AAQS) or to any applicable PSD increments or PSD Significant Impact Levels (SILs) from the Project. Also, air-quality–related values (AQRVs) are evaluated; no negative impact to visibility, terrestrial, or aquatic resources is predicted.

- Section 5.1.3, Cumulative Impacts Analyses, presents the results of cumulative impacts analysis (including off-Project sources that have been permitted but historically have operated at less than their full potential to emit air pollutants, or are in the process of being permitted, and are not yet operational).

- Section 5.1.4, Mitigation Measures, describes the Project's emission offsets.

- Section 5.1.5, Laws, Ordinances, Regulations, and Standards, describes all applicable laws, ordinances, regulations, and standards (LORS). Section 5.1.5 also provides an analysis of best available control technology (BACT) for the Project.

- Section 5.1.6, Involved Agencies and Agency Contacts, lists the agency contacts used to conduct the air quality assessment.

- Section 5.1.7, Permits Required and Permit Schedule, lists the permits required and provides a permit schedule.

- Section 5.1.8, References, lists the references used to conduct the air quality assessment.

Some air quality data are presented in other sections of this Revised Application for Certification (AFC), including an evaluation of toxic air pollutants (see Section 5.6, Public Health), and information related to the fuel characteristics, heat rate, and expected capacity factor of the Project (see Section 2, Project Description).

The Modeling Protocol (URS 2009) was submitted for review to CEC, USEPA, and the SJVAPCD on February 6, 2009. Since the development of the Protocol, the Project has undergone certain refinements. Section 2.0, Project Description, contains the comprehensive description of the Project and its operations. None of the refinements made to the Project subsequent to development of the Modeling Protocol affect the appropriateness of the Modeling Protocol for use in analyzing Project impacts. Comments on the Modeling Protocol were received from CEC and USEPA. Those comments, and Applicant's response thereto, are included in Appendix C (Air Modeling) of this Revised AFC.

5.1.1 Affected Environment

This section describes the regional climate and meteorological conditions that influence transport and dispersion of air pollutants and the existing air quality within the Project region. The data presented in this section are representative of the Project Site as well as Controlled Area, described below.

The Project Site consists of approximately 473 acres located near hydrocarbon-producing area in Kern County, California, as shown in Figure 2-1, Project Vicinity. 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. This Controlled Area is shown on Figure 2-4, Site Plan. 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

For the purposes of the Air Quality analysis, impacts were determined outside of both the Project Site and the Controlled Area combined.

5.1.1.1 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 5.1-2, 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.

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.

Table 5.1- 2
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.

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.

5.1.1.2 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 AirData (2008) and the CARB-California Air Quality Data website (2008). The maximum concentration recorded at these monitoring stations over the most recent 3-year period will be used as a conservative representation of existing air quality conditions 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 kilometers) 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 kilometers) 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 kilometers) 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 5.1-3 through 5.1-8. 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). Ozone occurs in two layers of the atmosphere. The layer surrounding the earth's surface is the troposphere. Here, ground level O_3 is an air pollutant that damages human health, vegetation, and many common materials. It is a key ingredient of urban smog. The troposphere extends to a level about 10 miles up, where it meets the second layer, the stratosphere. In contrast, the beneficial or stratospheric O_3 layer extends upward from about 10 to 30 miles and protects life on earth from the sun's harmful ultraviolet rays.

Ground level O_3 is what is known as a photochemical pollutant. Significant O_3 formation generally requires an adequate amount of precursors in the atmosphere and several hours in a stable atmosphere with strong sunlight.

Ozone is a regional air pollutant. It is generated over a large area and is transported and spread by wind. O_3, the primary constituent of smog, is the most complex, difficult to control, and the most pervasive of the criteria pollutants. Unlike other pollutants, O_3 is not emitted directly into the air by specific sources. O_3 is created by sunlight acting on other air pollutants (called precursors), specifically NO_x and VOC. Sources of precursor gases to the photochemical reaction that form O_3 number in the thousands. Common sources include consumer products, gasoline vapors, chemical solvents, and combustion products of various fuels. Originating from gas stations, motor vehicles, large industrial facilities, and small businesses such as bakeries and dry cleaners, the O_3-forming chemical reactions often take place in another location, catalyzed by sunlight and heat. High O_3 concentrations can form over large regions when emissions from motor vehicles and stationary sources are carried hundreds of miles from their origins.

SJVAB is designated as a non-attainment area for O_3 (state 1-hour, state 8-hour, and federal 8-hour). Table 5.1-3, Ambient Ozone Levels at Shafter-Walker Street, 1999 – 2008, shows that the federal 8-hour O_3 AAQS of 0.08 part per million (ppm) has been frequently exceeded in the past 10 years at the Shafter-Walker Street Station, and that the federal 1-hour O_3 AAQS 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 frequently has been 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.

Particulate Matter (PM_{10} and $PM_{2.5}$). PM_{10} refers to particles less than or equal to 10 microns in aerodynamic diameter. $PM_{2.5}$ refers to particles less than or equal to 2.5 microns in aerodynamic diameter and are a subset of PM_{10}. Particulate matter pollution consists of very small liquid and solid particles floating in the air. Some particles are large or dark enough to be seen as soot or smoke. Others are so small they can be detected only with an electron microscope. Particulate matter is a mixture of materials that can include smoke, soot, dust, salt, acids, and metals. Particulate matter also forms when gases emitted from motor vehicles and industrial sources undergo chemical reactions in the atmosphere.

In the western U.S., there are sources of PM_{10} in both urban and rural areas. PM_{10} and $PM_{2.5}$ are emitted from stationary and mobile sources, including diesel trucks and other motor vehicles; power plants; industrial processing; wood-burning stoves and fireplaces; wildfires; dust from

Table 5.1-3
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.
Maximum average values occurring during the most recent 3 years are indicated in bold.
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.
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

roads, construction, landfills, and agriculture; and fugitive windblown dust. Because particles originate from a variety of sources, their chemical and physical compositions vary widely.

SJVAB is designated as a non-attainment area for PM_{10} and $PM_{2.5}$. Table 5.1-4, Ambient PM_{10} Levels at Bakersfield Golden State Highway, 1999 – 2008, shows that the 24-hour average CAAQS of 50 micrograms per cubic meter ($\mu g/m^3$) for PM_{10} has been frequently exceeded in the Bakersfield area. The federal 24-hour average PM_{10} AAQS of 150 $\mu g/m^3$ was exceeded six times within the past 10 years (in 1999 – 2002, 2006, and 2008). The maximum 24-hour PM_{10} background concentration of 266 $\mu g/m^3$ was measured at the Bakersfield Golden Highway Station in 2008.

The annual geometric mean presented in Table 5.1-4, 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 – 2006 are above the California PM_{10} ambient air quality standard of 20 $\mu g/m^3$. The annual geometric concentrations from 2007 and 2008 are currently unavailable.

Table 5.1-4
Ambient PM_{10} 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	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 $\mu g/m^3$)	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
$\mu g/m^3$ = micrograms per cubic meter

The annual and 24-hour $PM_{2.5}$ data are presented in Table 5.1-5, 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, 98th percentile is above the federal AAQS of 35 $\mu g/m^3$. The 3-year average, arithmetic mean is above the California AAQS of 12 $\mu g/m^3$.

Table 5.1- 5
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 federal AAQS of 35 $\mu g/m^3$.
[b] The 3-Year Average, Arithmetic Mean is above the CAAQS of 12 $\mu g/m^3$
Maximum average values occurring during the most recent 3 years are indicated in bold.
– = Data not available
mg/m^3 = micrograms per cubic meter

Carbon Monoxide (CO). Carbon monoxide is emitted by mobile and stationary sources as a result of incomplete combustion of hydrocarbons or other carbon-based fuels. CO is an odorless, colorless, air pollutant gas that is highly reactive.

Carbon monoxide is a by-product of motor vehicle exhaust, which contributes more than two-thirds of all CO emissions nationwide. In cities, automobile exhaust can cause as much as 95 percent of all CO emissions. These emissions can result in high concentrations of CO, particularly in local areas with heavy traffic congestion. Other sources of CO emissions include industrial processes and fuel combustion in sources such as boilers and incinerators. Despite an overall downward trend in concentrations and emissions of CO, some metropolitan areas still experience high levels of CO.

SJVAB is designated as an attainment area for CO. The data in Table 5.1-6, Ambient CO Levels at Bakersfield-Golden State Highway, 1999-2008, show that the measured concentrations of CO are all below the applicable federal and California standards.

Table 5.1-6
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

Nitrogen Oxides (NO_x). Nitrogen oxides are a family of highly reactive gases that are a primary precursor to the formation of ground level O_3, and react in the atmosphere to form acid rain. NO_x is emitted from the use of solvents and combustion processes in which fuel is burned at high temperatures, principally from motor-vehicle exhaust and stationary sources, such as electric utilities and industrial boilers. NO_2, a brownish gas, is a strong oxidizing agent that reacts in the air to form corrosive nitric acid, as well as toxic organic nitrates.

SJVAB is designated as an attainment area for NO_2. The data in Table 5.1-7, 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 5.1-7
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.

Sulfur Dioxide (SO_2). Sulfur dioxide is a colorless, irritating gas formed primarily by the combustion of sulfur-containing fossil fuels. Historically, in the late 1970s in the SJVAB portion of Kern County, SO_2 was a pollutant of concern, but with the successful application of regulations, the levels have been reduced significantly.

SJVAB is designated as an attainment area for SO_2. The data in Table 5.1-8, Ambient SO_2 Levels Nearest to the Project Location, 1999 – 2008, show that the measured concentrations of SO_2 are all below the applicable federal and California standards.

Table 5.1-8
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 2009
Notes:
a All 1-hour average concentrations are below the California SO_2 ambient air quality standard of 0.25 ppm (655 µg/m^3).
b All 24-hour average concentrations are below the California SO_2 ambient air quality standard of 0.04 ppm (105 µg/m^3) and the federal AAQS of 0.14 ppm (365 µg/m^3).
c All annual average concentrations are below the federal SO_2 AAQS of 0.03 ppm (80 µg/m^3)
d It was observed that higher monitoring concentrations were observed at the Fresno 1st Street station on July 4 and 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 USEPA Rule 40 CFR 50.14. Therefore, concentrations on July 4 and 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

Other Pollutants

Volatile Organic Compounds (VOCs). VOCs includes all hydrocarbons except those exempted by CARB. Therefore, VOCs are a set of organic gases based on state rules and regulations. Reactive organic gases (ROG) are similar to VOCs in that they include all organic gases except those exempted by federal law. The list of compounds exempt from the definition of VOCs is included by the SJVAPCD and is presented in District Rule 1102. Both VOCs and ROGs are emitted from incomplete combustion of hydrocarbons or other carbon-based fuels. Combustion engine exhaust from automobiles and trucks, oil refineries, and oil-fueled power plants are the primary sources of hydrocarbons. Another source of hydrocarbons is evaporation from petroleum fuels, solvents, dry cleaning solutions, and paint.

Sulfates (SO_3 and SO_4). Sulfates are the fully oxidized ionic form of sulfur. Sulfates occur in combination with metal and/or hydrogen ions. In California, emissions of sulfur compounds occur primarily from the combustion of petroleum-derived fuels (e.g., gasoline and diesel fuel) that contain sulfur. This sulfur is oxidized to SO_2 during the combustion process and subsequently converted to sulfate compounds in the atmosphere. The conversion of SO_2 to sulfates takes place comparatively rapidly and completely in urban areas of California due to regional meteorological features.

Lead (Pb). Lead is a metal that is a natural constituent of air, water, and the biosphere. Lead is neither created nor destroyed in the environment, so it essentially persists forever. Lead was used until recently to increase the octane rating in auto fuel. Since gasoline-powered automobile engines were a major source of airborne Pb through the use of leaded fuels, and the use of leaded fuel has been mostly phased out, the ambient concentrations of Pb have dropped dramatically. Kern County no longer monitors Pb in the ambient air of the SJVAB.

Hydrogen Sulfide (H_2S). Hydrogen sulfide is associated with geothermal activity, oil and gas production, refining, sewage treatment plants, and confined animal feeding operations. It has a characteristic "rotten egg" odor.

5.1.2 Environmental Consequences

This section describes the analyses conducted to assess the potential air quality impacts from the Project. Impacts from the Project are considered significant if, when combined with background ambient levels, they will cause an exceedance of an ambient air quality standard, or contribute to an existing exceedance, or if by themselves, they will exceed an applicable PSD significant impact amount. Emissions estimates for both construction and operation of the Project are presented. Dispersion model selection and setup are also described (i.e., emissions scenarios and release parameters, building wake effects, meteorological data, and receptor locations), and analysis results are presented.

5.1.2.1 Construction Emissions

The primary emission sources during construction will include heavy construction equipment, construction vehicles, and fugitive dust from disturbed areas due to grading, excavating, and construction of Project structures. Different areas within the Project Site will be disturbed at different times during the 44-month overall construction period (37 months of site preparation and construction and up to 10 months of commissioning and startup, with overlap). Estimated land disturbance for major construction activities is summarized in Table 5.1-1 above, and Chapter 2, Project Description.

Construction equipment and vehicle exhaust emissions were estimated using equipment lists and construction scheduling information provided by the Project design engineering firm, presented in Chapter 2, Project Description, and Appendix D (Air Quality Emissions and Calculations) of this Revised AFC. Equipment-specific emission factors were used to estimate mass emissions for all criteria pollutants from diesel-fueled construction equipment and vehicles using South Coast Air Quality Management District's (SCAQMD) OFFROAD Emission Factors. Assumptions used in calculating Project construction emissions include a 44-month construction period; 22 construction days per month; a single-shift, 10-hour workday; and a 50-hour workweek. Emission factors for gasoline-fueled construction equipment are based on OFFROAD 2007 emission factors.

Table 5.1-9, Construction Equipment Usage Schedule (on site), presents a list of equipment needed during construction and the estimated number of pieces of equipment that would operate during each month of the construction effort. Emissions from equipment will occur over a 44-month construction period. The list of fueled equipment needed during each month of the construction effort (as shown in Table 5.1-9) served as the basis for estimating pollutant emissions throughout the term of construction and helped to identify the periods of probable maximum short-term emissions. The equipment numbers contained in Table 5.1-9 might differ slightly from the total piece counts equipment numbers shown in Project Description, Table 2. Reasons for this include: some construction equipment is used offsite for at least some portion of the time, some construction equipment is used off-shift from the normal work day, and the overall use rate varies by equipment type.

An ultra-low fuel sulfur content of 0.0015 percent by weight (15 ppm) was assumed for all diesel construction equipment operations.

Estimated land disturbance for major construction activities is summarized in Table 5.1-1 above, and Section 2, Project Description.

- Fugitive dust emissions resulting from on-site soil disturbances were estimated using SCAQMD California Environmental Quality Act (CEQA) Handbook (SCAQMD 1993) and SJVAPCD emission factors for bulldozing and dirt-pushing, travel on unpaved roads, and handling/storage of aggregate materials. A dust control efficiency of 67 percent for Project Site and temporary construction area activities was assumed to be achieved for these activities by frequent watering, speed control, or other measures when required.

- Emissions from on-road delivery trucks and worker commute trips were estimated using trip generation information presented in Section 2.7.8, Combined Construction Traffic, and emission factors provided by SCAQMD for On-road Vehicles from the EMFAC2007 model. Construction workers were assumed to commute to the Project Site from locations within Kern County.

Table 5.1-9
Construction Equipment Usage Schedule
(on site)

Equipment	# of units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
On-Road Vehicles																																													
Concrete Pumper Truck	20	0	0	0	0	0	0	0	0	1	1	2	2	2	2	2	2	2	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dump Truck	32	3	3	3	3	3	3	3	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pile Driver Truck	14	0	0	0	3	3	3	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trucks – Pickup 3/4 ton	220	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Trucks ─ 3 ton	68	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	0	0	0	0
Truck ─ Water	58	4	4	4	4	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Off-Road Vehicles																																													
Air Compressor 750 CFM	94	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	3	4	4	4	4	4	4	4	4	4	4	4	4	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1
Bulldozer D10R	24	3	3	3	3	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bulldozer D4C	26	3	3	3	3	2	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Concrete Trowel Machine	23	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	0	0	0	0	0	0	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cranes ─ Mobile 35 ton	163	0	0	0	0	0	0	1	1	1	4	4	4	4	7	7	7	7	7	7	7	7	7	7	7	7	7	5	5	5	5	5	5	5	5	2	2	2	1	1	1	1	1	1	1
Cranes 100 / 150 ton cap	116													1	2	4	4	5	5	6	6	6	6	6	6	6	6	6	6	5	5	5	5	4	4	3	2	2							
Diesel-Powered Welder	79	0	0	0	0	0	0	0	0	0	0	0	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	2	2	2	2	2	1	1	1	0	0	0	0	0	0	0	0
Excavator ─ Backhoe/loader	101	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	3	3	4	5	5	5	5	5	5	5	5	5	4	4	4	2	2	1	1	1	1	1	1
Excavator ─ Earth Scraper	55	2	2	3	4	4	4	4	4	4	4	4	2	2	2	2	2	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator ─ loader	28	8	8	6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Excavator ─ Motor Grader (CAT140H)	24	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fired Heaters	15	3	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Forklift	113	0	0	0	0	1	2	2	3	3	3	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0
Heavy Haul/Cranes	75	0	0	0	0	0	0	0	1	1	1	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1

Table 5.1-9
Construction Equipment Usage Schedule
(on site)

Equipment	# of units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
Light Plants	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Compaction Roller	217	0	0	0	2	2	2	2	2	2	2	2	2	6	6	6	6	6	6	6	6	6	6	8	8	8	8	8	8	8	8	8	8	8	8	8	8	4	4	4	3	3	3	3	3
Portable Compaction ─ Vibratory Plate	49	0	0	2	3	3	3	3	3	0	0	0	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0
Pumps	45	0	0	0	0	0	0	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Portable Power Generators	93	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	1	1	1	1	1	1	0	0
Truck Crane ─ Greater than 200-ton	72	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	3	3	4	4	4	4	4	4	4	4	4	4	4	3	3	2	2	2	1	0	0	0	0	0	0	0
Truck Crane ─ Greater than 300-ton	38	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	3	3	3	3	3	3	3	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Vibratory Roller Ingersol-Rand 20-ton	37	5	5	5	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
On-Road Total	412	13	13	13	16	41	14	14	13	13	13	12	12	11	11	11	10	10	9	9	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	7	6	6	6	6	5	5	5	5
Off-Road Total	1690	31	30	31	33	26	27	29	34	35	37	41	42	46	51	52	52	55	54	56	60	61	58	59	60	61	61	58	55	49	47	47	45	40	34	28	26	16	11	10	9	9	9	8	7
Project Total	**2102**	**44**	**43**	**44**	**49**	**40**	**41**	**43**	**47**	**48**	**50**	**53**	**54**	**57**	**62**	**63**	**62**	**65**	**63**	**65**	**69**	**70**	**66**	**67**	**68**	**69**	**69**	**66**	**63**	**57**	**55**	**55**	**53**	**48**	**42**	**36**	**33**	**22**	**17**	**16**	**15**	**14**	**14**	**13**	**12**
		Month																																											
Schedule																																													
Site Mobilization		■																																											
Site Prep/Piling		■	■	■	■	■	■	■																																					
Construction							■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■							
Commissioning and Startup																																						■	■	■	■	■	■	■	■	■	■

Source: HECA Project

- The short-term maximum emissions were calculated from the construction equipment list from the 21st month of the construction schedule. Activities in the 21st month include excavating, material handling, and extensive building construction. Annual emissions were based on the worst 12 consecutive months of the construction period, which are months 17 through 28 of construction.

- The emissions from each disturbed area are presented as either area sources for fugitive dust or point sources for combustion emissions for all pollutants. Point sources were selected so that the O_3 limiting method (OLM) version of the AERMOD dispersion model could be used to calculate NO_2 emissions. To apply the OLM option in AERMOD to predict NO_2 concentrations, hourly O_3 data are required. Hourly O_3 data recorded at the SJVAPCD Bakersfield California Avenue monitoring station for the same 5 years as the input meteorological data were used in this analysis.

- The equipment point source emissions were calculated by means of the emission spreadsheet in Appendix D, and stack parameters for different-sized (horsepower) equipment. These stack parameters were obtained from the CARB document *Risk Management Guidance for the Permitting of New Stationary Source Diesel-Fueled Engines, October 2000.*

Detailed spreadsheets are provided in Appendix D, which has calculations of emissions from all Project construction activities and equipment, as well as the data and assumptions used for the calculations. Table 5.1-10, Maximum Hourly, Daily, and Annual Construction Emissions, presents the estimated maximum daily, monthly, and annual Project construction emissions.

Table 5.1-10
Maximum Hourly, Daily, and Annual Construction Emissions

Activity	NO_X	CO	VOC	SO_X	PM_{10}	$PM_{2.5}$
Daily						
On-Road Total (lbs/day)	937.4	489.7	155.4	0.99	76.6	55
Off-Road Total (lbs/day)	11,208.5	4931	14,84	10.8	616.4	555.7
Total Max. Daily Emissions (lbs/day)	12,146	5421	1639	11.8	692.9	610.7
Annual						
Total Max. Annual Emissions (lbs/year)	139,200	17,1000	27,800	400	120,080	27,000
Total Max. Annual Emissions (tons/year)	69.6	85.5	13.9	0.2	60.0	13.5

Source: HECA Project

Notes:
[a] Worst-case daily daily emissions were estimated by dividing worst-case monthly emissions by 22 days. Total emissions were based on daily hours of equipment operation in a given month. Daily average hours of operation are shown in Appendix D.
[b] Worst-case annual emissions were estimated by summing emissions for each 12-month period (i.e., months 1 to 12, 2 to 13, etc.) during the 44-month construction period and taking the maximum emissions for the worst 12-month period (i.e., month 17 to 28 for CO, VOC, SO_X, PM_{10}, and NO_X).
NO_x = nitrogen oxides
CO = carbon monoxide
VOCs = volatile organic compounds
SO_x = sulfur oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter

5.1.2.2 Operational Emissions

5.1.2.2.1 Operational Emissions – Stationary Sources

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 an 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 fuel from the gasification plant, natural gas, or a mixture of the two; a heat-recovery steam generator (HRSG) with duct firing of hydrogen-rich fuel 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 fuel. 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
- Sulfur Recovery Unit (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

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 fuel, 100 percent natural gas, or co-firing hydrogen-rich fuel and natural gas. Most of the hydrogen-rich fuel from the gasification plant will be used to fully load the CTG, with any excess (up to about 10 to 14 percent) duct fired in the HRSG. The CTG will operate on hydrogen-rich fuel, natural gas, or a mixture of the two (45 to 90 percent hydrogen-rich fuel) 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 fuel 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 5.1-11, Maximum CTG/HRSG Operating Schedule.

Table 5.1-11
Maximum CTG/HRSG Operating Schedule

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

Source: HECA Project

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

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 percent, 80 percent, and 100 percent) and three ambient temperatures (20ºF, 65ºF, and 97ºF) when firing natural gas, syngas, or co-firing are presented in Table 5.1-12, 1-Hour Operating Emission Rates for CTG/HRSG Operating Load Scenarios.

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, hydrogen-rich fuel gas, or co-firing, the CTG/HRSG will always be started up using natural-gas fuel. Therefore, the expected emissions and duration of startup events summarized in Table 5.1-13, CTG/HRSG Criteria Pollutant Emission Rates During Startup and Shutdown, reflect the emission 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.

Table 5.1-12
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 Hydrogen-Rich Fuel													
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, and 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
NO_X = nitrogen oxides
ppm = parts per million
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
VOCs = volatile organic compounds

Table 5.1-13
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 percent 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 less than 10 microns in diameter, and is assumed to equal $PM_{2.5}$ = particulate matter 2.5 microns in diameter.
SO_2 = sulfur dioxide
VOCs = volatile organic compounds

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, hydrogen-rich fuel, 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, hydrogen-rich fuel, and co-firing) was calculated assuming two full cold starts, three shutdowns 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°F) without duct firing, and 4 hours of co-firing at the winter minimum (20°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 5.1-14, 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 5.1.2.3, Dispersion Modeling. Note that modeling of turbine commissioning impacts was conducted separately due to the temporary, one-time nature of this activity.

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 65°F for the specified number of hours per year. Emissions for normal operating hours with duct firing assumed the maximum

Table 5.1-14
Criteria Pollutant Sources and Emission Totals for the Worst-Case CTG Emissions Scenario for All Averaging Time

Averaging Time	Worst-Case Emission Scenarios by Operating Equipment	Pollutant	Emissions in pounds – Entire Period: CTG/HRSG (Natural Gas)	CTG/HRSG (Hydrogen-Rich Fuel)	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 starts, three shutdowns, 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 Total = 716.5	n/a	4 hrs = 136.0 Total = 716.5
	SO_X, PM_{10}: Continuous full-load turbine operation with duct firing (both turbines) at peak fuel use; except PM_{10} for natural gas: four cold starts, four shutdowns, 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 turbines operate 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 less than 10 microns in diameter, and is assumed to equal $PM_{2.5}$ = particulate matter 2.5 microns in diameter
SO_X = sulfur oxides
VOCs = volatile organic compounds

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 5.1-15, Average Annual Emissions per Turbine Operating Scenario. Emissions calculations for all scenarios are contained in Appendix D.

Table 5.1-15
Average Annual Emissions per Turbine Operating Scenario

Pollutant	HRSG Stack - Nat Gas (tons/yr/CT)	HRSG Stack - Hydrogen-Rich Fuel (tons/yr/CT)	HRSG Stack - Co Firing (tons/yr/CT)	Maximum (tons/yr/CT)
NO_X	148.0	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 less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOCs = volatile organic compounds

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 NOx 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 5.1-16, Maximum Auxiliary CTG Operating Schedule.

Table 5.1-16
Maximum Auxiliary CTG Operating Schedule

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

Source: HECA Project

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

Note:
CTG = combustion turbine generator

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 percent, 75 percent, and 100 percent) and three ambient temperatures (20ºF, 65ºF, and 97ºF) when firing natural gas are presented in Table 5.1-17, 1-Hour Operating Emission Rates for CTG/HRSG Operating Load Scenarios. Table 5.1-18, Auxiliary CTG Criteria Pollutant Emission Rates During Startup and Shutdown, summarizes the expected emissions and duration of startup and shutdown from the auxiliary CTG.

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 5.1-17
1-Hour Operating Emission Rates for Auxiliary CTG Operating Load Scenarios

Ambient Temperature	UNITS	Winter Minimum, 20°F				Yearly Average, 65°F				Summer Maximum, 97°F			
CTG Load Level	% Load	100%	100%	75%	50%	100%	100%	75%	50%	100%	100%	75%	50%
Evap Cooling Status	off / on	Off	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 (@ 2.5 ppm)	lb/hr		7.9	6.4	4.7	8.1		6.5	4.7	7.9		6.2	4.6
CO (@ 6.0 ppm)	lb/hr		11.5	9.3	6.9	11.9		9.4	6.9	11.5		9.1	6.8
VOC (@ 2.0 ppm)	lb/hr		2.2	1.8	1.3	2.3		1.8	1.3	2.2		1.7	1.3
SO_2 (@ 12.65 ppmv)	lb/hr		1.8	1.4	1.1	1.9		1.5	1.1	1.8		1.4	1.0
PM_{10} = $PM_{2.5}$	lb/hr		6.0	6.0	6.0	6.0		6.0	6.0	6.0		6.0	6.0
NH_3 (@ 10.0 ppm slip)	lb/hr		11.6	9.5	7.0	12.0		9.5	7.0	11.7		9.2	6.8

Source: HECA Project

Notes:
CO = carbon monoxide
CTG = combustion turbine generator
NH_3 = ammonia
NO_X = nitrogen oxides
ppm = parts per million
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOCs = volatile organic compounds

Table 5.1-18
Auxiliary CTG Criteria Pollutant Emission Rates During Startup and Shutdown

Cold Startup			Shutdown		
10 (min. in cold startup)	**Max 1-hour (lb/hr)**	**Total (lb/10 min.)**	**10.3 (min. in shutdown)**	**Max 1-hour (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-hour) assume 3 startups and 3 shutdowns.
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
NOX = nitrogen oxides
PM_{10} = particulate matter 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter (PM2.5 is assumed to equal PM_{10})
SO2 = sulfur dioxide
VOCs = volatile organic compounds

Table 5.1-19, Criteria Pollutant Sources and Emission Totals for the Worst-Case Auxiliary 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 5.1.2.3, Dispersion Modeling.

Table 5.1-19
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 less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
VOCs = volatile organic compounds

Power-Block Cooling Tower

Power-cycle heat rejection will consist of a steam surface condenser, cooling tower, and cooling water system. The heat rejection system receives exhaust steam from the low-pressure (LP) 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 (TDS) 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 TDS are dissolved in the circulating cooling water. A summary of the power block cooling tower emissions is presented in Table 5.1-20, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix D.

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 (three total, one per gasifier) during start-up. The gasifier warming burners operate at 18 million British thermal units (MMBtu) per 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 5.1-20, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix D.

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 [HHV]). 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 at 3 percent O_2. A summary of auxiliary boiler emissions is presented in Table 5.1-21, Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas at 59°F. Emissions and calculations are included in Appendix D.

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 5.1-20, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix D.

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 is 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 temperatures, and provides sufficient residence time in order to ensure essentially complete destruction of reduced sulfur compounds like H_2S to SO_2. The thermal oxidizer 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 5.1-20, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix D.

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 Block 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 5.1-20, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix D.

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 minimis* Good Engineering Practice (GEP) 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 5.1-20, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix D

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 5.1-20, Total Combined Annual Criteria Pollutant Emissions. Emissions and calculations are included in Appendix D.

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 (UPS), 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 5.1-20, 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.

Total Combined Facility-Wide Emissions

The total combined annual emissions from all emission sources of the Project are shown in Table 5.1-20, Total Combined Annual Criteria Pollutant Emissions.

Table 5.1-20
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 percent $PM_{2.5}$
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 less than 10 microns in diameter
$PM_{2.5}$ =particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOCs = volatile organic compounds

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 (MAC) and booster air compressor (BAC) 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 (LOX) and liquid nitrogen (LIN). The LOX is stored to provide a backup oxygen supply to cover a compressor trip or other short ASU outage. The LIN 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 LOX pumping and vaporization system can be started to make high-pressure O_2 vapor available to the Gasification Block.

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/petcoke 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 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 carbon dioxide 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 petcoke and/or petcoke-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 fuel. 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 fuel. 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:

- 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 steps involved in the commissioning of these four phases are given in Sections 2.6.4.1 through 2.6.4.4.

As described in Section 2.10, Facility Reliability, the startup and commissioning period of the Project (CTG, ASU, process block and BOP, IGCC) is expected to be completed within 1 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 exist for commissioning periods on power generation involving natural gas, and mature operation is reached within a few months for natural gas combined-cycle (NGCC)-type systems, the power generation involving hydrogen-rich fuel from solid feedstock such as petcoke 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 1-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 5.1-21, 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 5.1-21, 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.

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.

Table 5.1-21
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	Various	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	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 5.1-21
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)
Performance Testing								
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 less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOCs = volatile organic compounds

Once it has been installed, the oxidation catalyst will abate CO and VOC emissions from the gas turbine and the duct burners because it is essentially a passive device. Although the SCR catalyst is in some cases able to be installed prior to initial 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 Fuel

The combined-cycle block will require additional testing and NO_x tuning with hydrogen-rich fuel. The testing will cover the range of natural gas/hydrogen-rich fuel 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 fuel;
- CTG NO_x tuning on part load;
- Water wash and performance testing on hydrogen-rich fuel;
- Duct-burner testing on hydrogen-rich fuel;
- 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 5.1-22, Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen-Rich-Fuel at 59°F.

Table 5.1-22
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen-Rich Fuel 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 Fuel Co-firing	16	100%	50% SCR, 90% CO (*)	49	1,584	692	88	576
CTG NO_X Tuning @ 90% Hydrogen-Rich Fuel 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 Fuel	48	100%	Operating	128	2,386	869	168	1,728
Source Testing @ 100% Hydrogen-Rich Fuel	16	100%	Operating	38	738	269	51	576
Source Testing @ 100% Hydrogen-Rich Fuel	16	100%	Operating	43	795	290	56	576
Source Testing @ 45% Hydrogen-Rich Fuel Co-firing	16	100%	Operating	49	634	386	88	576
Source Testing @ 90% Hydrogen-Rich Fuel 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

Table 5.1-22
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen-Rich Fuel 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 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 through 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 less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOCs = volatile organic compounds

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.

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 5.1-23, Duration and Criteria Pollutant Emissions for Commissioning of the Auxiliary CTG on Natural Gas at 59°F.

Table 5.1-23
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 less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOCs = volatile organic compounds

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.

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 CARB to assign emissions targets to each sector in the California economy and to develop regulatory and market methods to ensure compliance, which takes 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 D 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 use 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.

5.1.2.2.2 Operational Emissions – Mobile Sources

Mobile Source Emissions – Off-Site

Trucks carrying petcoke would travel to the Project Site from various refineries in the Carson Area, the Santa Maria Area, and the Bakersfield Area. Trucks carrying coal would travel to the Project Site from a nearby transloading terminal. Coal would be transported into the state by rail to a nearby transloading terminal from mines in the western U.S. There are two operating scenarios. The first operating scenario uses 100 percent petcoke and the scenario occurs 80 percent of the time. The second operating scenario uses 75 percent coal and 25 percent petcoke (on a btu basis) and the scenario occurs 20 percent of the time. In addition, trucks carrying chemical shipments, gasification solids, molten sulfur, and the ZLD solids would travel to and from the Project Site to various facilities in Kern County.

Emissions from transportation of feedstock and miscellaneous chemicals and waste to and from the Project Site are compared to emissions from transportation under the current practice scenario to determine what the net difference in emissions is. The current practice scenario depicts material handling done with the petcoke at the present time. These activities would be displaced after the Project is operational. A comparison between the current practices and the proposed Project practices is shown on Table 5.1-24.

Table 5.1-24
Feedstock Mobile Source Routes

Feedstock (percent of total)	Current Practice	Project Site Practice
California Petcoke, Carson Area (45%)	Regular trucks from Carson to Port of Long Beach; Shipped to Asia	Model Year 2010 trucks from Carson to Project Site via Interstate 5
California Petcoke, Santa Maria Area (45%)	Regular rail to Port of Long Beach via coastal railway; Shipped to Asia	Model Year 2010 trucks from Santa Maria to Project Site via Highway 46
California Petcoke, Bakersfield Area (5%)	Regular trucks to Port of Long Beach via Highway 99 then Interstate 5; Shipped to Asia	Model Year 2010 trucks to Project Site via Highway 58
California Petcoke, Bakersfield Area (5%)	Regular trucks to locations within SJV Air Basin.	Model Year 2010 trucks to Project Site via Highway 58
Western Bituminous Coal (100%)	Not applicable	Regular rail to Transloading Terminal, Model Year 2010 Trucks from Transloading Terminal to Project Site

Notes: Primary route only shown. Feeder routes are not shown.

The table above only shows truck and rail route for the petcoke and coal feedstock. In addition, miscellaneous chemicals will be transported to the Project Site from various facilities in Kern County. Plant waste and other by-products like gasification solids, molten sulfur, and the ZLD solids will be transported from the Project Site to various facilities in Kern County. Such truck routes do not exist under the current practice scenario.

Heavy-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. For trucks traveling to and from the Project Site, only model 2010 trucks were used. For trucks traveling from the various refineries under the current practice scenario, the default range in the EMFAC2007 model was used (i.e., trucks from model years 1971 to 2015 comprising the truck fleet). Emission factors from EMFAC2007 were presented in tons per day and are estimated by air basin. Using the vehicle miles traveled (VMT) provided in the EMFAC2007, emission factors in pounds per day were calculated for the criteria pollutants and greenhouse gases (CO_2 and CH_4 only). The emission factor for N_2O was derived from California Climate Action Registry (CCAR) General Reporting Protocol Version 3.1 (January 2009), Table C4 using the mileage accrual rates by age table from EMFAC2007 (annual odometer mileage weighted by population) for diesel fueled heavy-heavy duty trucks. All truck routes are considered to be round-trip routes, and are differentiated by the air basin they are in, because emission factors vary depending on air basin.

The emissions factors for all criteria pollutants, except sulfur dioxides for locomotives pulling the additional railcars, were taken from the USEPA document EPA 420-F97-051 (Technical Highlights: Emission Factors for Locomotives). Idling emissions for the locomotive were obtained from USEPA document EPA420-B-04-002 (Guidance for Quantifying and Using Long Duration Switch Yard Locomotive Idling Emission Reductions in State Implementation Plans). These emission factors for locomotives in motion were presented in units of grams per gallon, and for locomotives in idle state in units of grams per hour. The sulfur dioxides emission factor was based on the California state regulation that requires intrastate diesel-electric locomotives that operate 90 percent of the time in the state to use only California ultra-low sulfur (15 parts per million) diesel fuel. The emission factor for CO_2 was obtained from the USEPA document EPA 420-F-05-001 (Average Carbon Dioxide Emissions Resulting from Gasoline and Diesel Fuel). The emission factors for the other greenhouse gases (CH_4 and N_2O) were derived from CCAR General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type). Statistics from the Bureau of Transportation Statistics indicated that in 2006, approximately 62 rail cars were in use for every locomotive that was in use, and the fuel efficiency of the locomotives was 0.13 mile per gallon.

Transportation emissions for Project Site and current practice scenarios were compared for statewide emissions and for emission per air basin. The air basins affected when comparing the Project Site transportation emissions and the current practice transportation emissions were the San Joaquin Valley, South Coast, South Central Coast, and Mojave Desert. The net difference was obtained by subtracting current practice emissions from Project Site emissions. The net difference for statewide emissions showed an increase for all pollutants, except for a decrease in emissions for CH_4, NO_X and SO_X. The statewide net emission differences are summarized in Table 5.1-25. The net difference for the San Joaquin Valley Air Basin showed an increase for all pollutants. The net emission differences for the San Joaquin Valley Air Basin are summarized in Table 5.1-26. The net difference for the South Coast Air Basin showed a net reduction in emissions for all pollutants, except for an increase in CO_2 emissions and a slight increase in SO_X emissions. The net emission differences for the South Coast Air Basin are summarized in Table 5.1-27. The net difference for the South Central Coast Air Basin showed a net reduction for all criteria pollutant emissions except for a slight increase in CO emissions and an increase for CO_2 emissions. The net emission differences for the South Central Coast Air Basin are summarized in Table 5.1-28. The net difference for the Mojave Desert Air Basin was the largest net increase for most pollutants because the majority of the coal train route occurs there, and there were no emissions associated with the air basin under the current practices. The net emission differences for the Mojave Desert Air Basin are summarized in Table 5.1-29.

Mobile Source Emissions – On-Site

On-site truck trip emissions were incorporated in the dispersion modeling. Trucks delivering coal and petcoke 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 5.1-30.

Table 5.1-25
Statewide Net Emission Difference

Operation Emissions tons/year	CO	CO_2	CH_4	N_2O	NO_x	PM_{10}	$PM_{2.5}$	SO_x	ROG
Current Scenario									
Route 1 (California Petcoke, Santa Maria Area)	7.51	2,744.87	0.08	0.03	41.10	1.44	1.33	2.05	2.38
Route 2 (California Petcoke, Carson Area)	1.18	671.41	0.01	1.69E-03	3.22	0.17	0.14	0.01	0.28
Route 3 (California Petcoke, Bakersfield Area)	1.78	1,019.15	0.02	2.57E-03	4.99	0.24	0.20	0.01	0.43
Route 4 (California Petcoke, Bakersfield Area)	3.01	1,729.77	0.03	4.40E-03	8.86	0.38	0.31	0.02	0.72
Misc. Trucks	–	–	–	–	–	–	–	–	–
Coal	–	–	–	–	–	–	–	–	–
Statewide Total	**13.48**	**6,165.21**	**0.15**	**0.04**	**58.17**	**2.23**	**1.99**	**2.08**	**3.81**
Project Site Scenario									
Route 1 (California Petcoke, Santa Maria Area)	7.23	8,471.11	0.02	0.02	14.77	0.85	0.76	0.04	1.70
Route 2 (California Petcoke, Carson Area)	6.43	7,712.72	0.05	0.02	13.33	0.72	0.51	0.06	1.27
Route 3 (California Petcoke, Bakersfield Area)	0.12	155.70	8.33E-04	3.99E-04	0.26	0.01	0.01	1.67E-03	0.03
Route 4 (California Petcoke, Bakersfield Area)	0.12	155.70	8.33E-04	3.99E-04	0.26	0.01	0.01	1.67E-03	0.03
Misc. Trucks	0.83	1,032.17	0.01	2.65E-03	1.75	0.09	0.06	0.01	0.18
Coal	4.40	2,058.38	0.05	0.02	22.36	0.80	0.73	0.29	1.33
Statewide Total	**19.13**	**19,585.78**	**0.12**	**0.06**	**52.74**	**2.49**	**2.07**	**0.41**	**4.54**
Difference	**5.65**	**13,420.58**	**(0.03)**	**0.03**	**(5.43)**	**0.25**	**0.08**	**(1.67)**	**0.73**

Table 5.1-26
San Joaquin Valley Air Basin Net Emission Difference

Operation Emissions tons/year	CO	CO_2	CH_4	N_2O	NO_x	PM_{10}	$PM_{2.5}$	SO_x	ROG
Current Scenario									
Route 1 (California Petcoke, Santa Maria Area)	–	–	–	–	–	–	–	–	–
Route 2 (California Petcoke, Carson Area)	–	–	–	–	–	–	–	–	–
Route 3 (California Petcoke, Bakersfield Area)	0.55	313.95	0.01	7.98E-04	1.61	0.07	0.06	3.05E-03	0.13
Route 4 (California Petcoke, Bakersfield Area)	3.01	1,729.77	0.03	4.40E-03	8.86	0.38	0.31	0.02	0.72
Misc. Trucks	–	–	–	–	–	–	–	–	–
Coal	–	–	–	–	–	–	–	–	–
Basin Total	**3.56**	**2,043.71**	**0.04**	**0.01**	**10.47**	**0.45**	**0.37**	**0.02**	**0.85**
Project Site Scenario									
Route 1 (California Petcoke, Santa Maria Area)	2.81	3,497.74	0.02	0.01	5.93	0.30	0.21	0.04	0.60
Route 2 (California Petcoke, Carson Area)	2.34	2,918.15	0.02	0.01	4.95	0.25	0.17	0.03	0.50
Route 3 (California Petcoke, Bakersfield Area)	0.12	155.70	8.33E-04	3.99E-04	0.26	0.01	0.01	1.67E-03	0.03
Route 4 (California Petcoke, Bakersfield Area)	0.12	155.70	8.33E-04	3.99E-04	0.26	0.01	0.01	1.67E-03	0.03
Misc. Trucks	0.83	1,032.17	0.01	2.65E-03	1.75	0.09	0.06	0.01	0.18
Coal	1.03	823.09	0.01	3.47E-03	3.86	0.15	0.13	0.28	0.28
Basin Total	**7.25**	**8,582.56**	**0.05**	**0.02**	**17.01**	**0.82**	**0.58**	**0.36**	**1.61**
Difference	**3.69**	**6,538.85**	**0.01**	**0.02**	**6.54**	**0.37**	**0.21**	**0.34**	**0.76**

Table 5.1-27
South Coast Air Basin Net Emission Difference

Operation Emissions tons/year	CO	CO_2	CH_4	N_2O	NO_x	PM_{10}	$PM_{2.5}$	SO_x	ROG
Current Scenario									
Route 1 (California Petcoke, Santa Maria Area)	3.76	1,372.44	0.04	0.01	20.55	0.72	0.66	0.01	1.19
Route 2 (California Petcoke, Carson Area)	1.18	671.41	0.01	1.69E-03	3.22	0.17	0.14	0.01	0.28
Route 3 (California Petcoke, Bakersfield Area)	1.23	705.21	0.01	1.78E-03	3.38	0.18	0.15	0.01	0.30
Route 4 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Misc. Trucks	–	–	–	–	–	–	–	–	–
Coal	–	–	–	–	–	–	–	–	–
Basin Total	**6.17**	**2,749.06**	**0.07**	**0.02**	**27.15**	**1.06**	**0.95**	**0.03**	**1.77**
Project Site Scenario									
Route 1 (California Petcoke, Santa Maria Area)	–	–	–	–	–	–	–	–	–
Route 2 (California Petcoke, Carson Area)	4.09	4,794.57	0.03	0.01	8.38	0.47	0.34	0.03	0.77
Route 3 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Route 4 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Misc. Trucks	–	–	–	–	–	–	–	–	–
Coal	–	–	–	–	–	–	–	–	–
Basin Total	**4.09**	**4,794.57**	**0.03**	**0.01**	**8.38**	**0.47**	**0.34**	**0.03**	**0.77**
Difference	**(2.08)**	**2,045.51**	**(0.03)**	**(0.00)**	**(18.76)**	**(0.59)**	**(0.62)**	**0.01**	**(1.00)**

Table 5.1-28
South Central Coast Air Basin Net Emission Difference

Operation Emissions tons/year	CO	CO_2	CH_4	N_2O	NO_x	PM_{10}	$PM_{2.5}$	SO_x	ROG
Current Scenario									
Route 1 (California Petcoke, Santa Maria Area)	3.76	1,372.44	0.04	0.01	20.55	0.72	0.66	2.04	1.19
Route 2 (California Petcoke, Carson Area)	–	–	–	–	–	–	–	–	–
Route 3 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Route 4 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Misc. Trucks	–	–	–	–	–	–	–	–	–
Coal	–	–	–	–	–	–	–	–	–
Basin Total	**3.76**	**1,372.44**	**0.04**	**0.01**	**20.55**	**0.72**	**0.66**	**2.04**	**1.19**
Project Site Scenario									
Route 1 (California Petcoke, Santa Maria Area)	4.42	4,973.36	–	0.01	8.84	0.55	0.55	–	1.11
Route 2 (California Petcoke, Carson Area)	–	–	–	–	–	–	–	–	–
Route 3 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Route 4 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Misc. Trucks	–	–	–	–	–	–	–	–	–
Coal	–	–	–	–	–	–	–	–	–
Basin Total	**4.42**	**4,973.36**	–	**0.01**	**8.84**	**0.55**	**0.55**	–	**1.11**
Difference	**0.66**	**3,600.93**	**(0.04)**	**(0.00)**	**(11.71)**	**(0.17)**	**(0.11)**	**(2.04)**	**(0.08)**

Table 5.1-29
Mojave Desert Air Basin Net Emission Difference

Operation Emissions tons/year	CO	CO_2	CH_4	N_2O	NO_x	PM_{10}	$PM_{2.5}$	SO_x	ROG
Current Scenario									
Route 1 (California Petcoke, Santa Maria Area)	–	–	–	–	–	–	–	–	–
Route 2 (California Petcoke, Carson Area)	–	–	–	–	–	–	–	–	–
Route 3 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Route 4 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Misc. Trucks	–	–	–	–	–	–	–	–	–
Coal	–	–	–	–	–	–	–	–	–
Basin Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Project Site Scenario									
Route 1 (California Petcoke, Santa Maria Area)	–	–	–	–	–	–	–	–	–
Route 2 (California Petcoke, Carson Area)	–	–	–	–	–	–	–	–	–
Route 3 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Route 4 (California Petcoke, Bakersfield Area)	–	–	–	–	–	–	–	–	–
Misc. Trucks	–	–	–	–	–	–	–	–	–
Coal	3.37	1,235.29	0.04	0.01	18.50	0.65	0.60	0.01	1.05
Basin Total	**3.37**	**1,235.29**	**0.04**	**0.01**	**18.50**	**0.65**	**0.60**	**0.01**	**1.05**
Difference	**3.37**	**1,235.29**	**0.04**	**0.01**	**18.50**	**0.65**	**0.60**	**0.01**	**1.05**

Table 5.1-30
On-Site Truck Trips by Period

Period	Petcoke 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 off site. Alternatively, they may drive around to the gasifier solids storage area where, they would offload 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 pickup and dropoff points, trucks would idle for about 5 to 10 minutes. The distance traveled within the site for all trucks would be less than 1 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 5.1-31.

Table 5.1-31
EMFAC2007 Heavy Truck Emission Factors and AERMOD Emission Rates

	Emission Factors from EMFAC			
Pollutant	**Onsite Petcoke and Coal Trucks**		**Onsite Gasifier Solids Handling Trucks**	
	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
SO_2	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 Petcoke and Coal Trucks		**Onsite Gasifier Solids Handling Trucks**	
	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
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.

5.1.2.3 Dispersion Modeling

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. Potential impacts of toxic air contaminant emissions from the Project are evaluated in Section 5.6, Public Health.

Separate criteria pollutant modeling analyses were conducted to address the air quality effects of emissions from Project construction activities and operations, because these activities will occur at different times. Impacts from construction activities include fugitive dust from road travel and excavation of disturbed areas and exhaust combustion products from diesel- and gasoline-fueled construction equipment and vehicles. 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 USEPA Region IX. 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 and Public Health Modeling Files provided with the AFC.

Model and Model Option Selections

The impacts of Project construction and operations on criteria pollutant concentrations in receptor areas within 31 miles (50 kilometers) 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.

Evaluation of construction, 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-kilometer) radius of the Project is classified as rural. Because the Auer classification scheme requires more than 50 percent of the area within the 1.9-mile (3-kilometer) 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.

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 1995a). 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 C.

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 DVDs that are being submitted with this Application.

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, located in the city of Bakersfield, within 20 miles (32.2 kilometers) east-northeast of the Project Site. These data have been pre-processed by the SJVAPCD with the Oakland upper-air data to create an input data set specifically tailored for input to AERMOD. The SJVAPCD prepared these data specifically for applicants' use for locations such as the Project Site.

The meteorological data recorded at Bakersfield Airport are acceptable for use at the Project Site for two reasons: proximity and terrain similarity. The terrain immediately surrounding the Project Site can be categorized as a fairly flat, or gradually sloping rural area in a region with developed oil wells. The terrain around the Bakersfield Airport also consists of relatively flat, or gradually sloping rural or suburban areas. Thus, the land use and the location with respect to near-field terrain features are similar. Both are located in areas of medium surface roughness (as opposed to low surface roughness like bodies of water or grassy prairies, or high surface roughness like highly urbanized cities or forests). Both locations are on the valley floor and are 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: 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.

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 kilometer beyond the Project Site and Controlled Area line;
- 500-meter spacing within 1 to 2 kilometers of Project sources; and
- 1,000-meter spacing within 2 to 10 kilometers of Project sources.

Figures 5.1-1, Near-Field Model Receptor Grid, and 5.1-2, 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 (USGS) digital elevation model (DEM) 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 kilometer 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 (HRA) modeling, with additional receptors placed at all sensitive locations (e.g., schools, hospitals, etc.) out to 10 kilometers (6 miles). Finally, discrete receptors will be placed at the locations of all nearby residences.

Construction Impacts Modeling

Section 5.1.2.1, Construction Emissions, details the development of the Project construction emissions estimates over the 44-month construction period. For purposes of evaluating construction air quality impacts, it is useful to break the construction schedule into a sequence of essentially non-overlapping phases, each occurring on specific areas of the Project Site and with characteristic equipment and vehicle requirements. An Excel spreadsheet was created to estimate pollutant emissions from construction activities, with separate worksheets for equipment exhaust and fugitive dust emissions associated with short-term and annual construction activities. Emissions from worker commuter trips to and from the Project Site during the construction period were also included (see Appendix C).

All construction activities were assumed to occur during a 10-hour work day. Calculation of annual emissions was based on a summation of overall construction activities for the consecutive 12-month period that will produce the highest emissions of all pollutants.

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 5.1-32, 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 D.

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 5.1-32, 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 and Public Health modeling DVDs that are provided separately with this Revised AFC.

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 5.1-32, Turbine Screening Results Normal Operations – Emissions and Stack Parameters per Turbine, 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. Because 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.

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 5.1-32, Turbine Screening Results Normal Operations – Emissions and Stack Parameters per Turbine). 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 D.

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.

Table 5.1-32
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 grain 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/m^3/(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

Table 5.1-32
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		
Maximum Concentration (μ g/m^3) Predicted per Pollutant Normal Operations (all receptors)										
NO_X 1-hour	77.313	86.394	94.140	88.001	98.030	137.252	83.280	8.450	9.502	11.779
NO_x annual	6.185	6.911	7.531	7.040	7.842	10.980	6.662	0.676	0.760	0.942
CO 1 hour	779.024	870.518	948.575	886.714	987.766	1382.977	839.142	28.276	31.795	39.414
CO 8 hour	545.317	609.363	664.003	620.700	691.436	968.084	587.399	19.793	22.256	27.590
SO_2 1 hour	4.050	4.525	4.931	4.610	5.135	7.189	4.362	0.975	1.096	1.359
SO_2 3 hour	3.645	4.073	4.438	4.149	4.621	6.470	3.926	0.878	0.987	1.223
SO_2 24 hour	1.620	1.810	1.972	1.844	2.054	2.876	1.745	0.390	0.439	0.544
SO_2 annual	0.324	0.362	0.394	0.369	0.411	0.575	0.349	0.078	0.088	0.109
PM_{10} 24 hour	6.627	7.405	8.069	7.543	8.403	11.764	7.138	1.690	1.900	2.356
PM_{10} annual	1.325	1.481	1.614	1.509	1.681	2.353	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

Notes:
[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 average time, 0.7 for an 8-hour average time, 0.4 for a 24-hr average time, and 0.08 for an annual average.

°F = degrees Fahrenheit
°K = degrees Kelvin
CO = carbon monoxide
CTG = combustion turbine generator
μg/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 less than 10 microns in diameter
SCR = selective catalytic reduction
SO_2 = sulfur dioxide

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 5.1-33, DEGADIS Model Inputs and Parameters.

Table 5.1-33
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

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 meters.

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

Because 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 (TIBL) 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. Because 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.

5.1.2.4 Compliance with Ambient Air Quality Standards

Air dispersion modeling was performed according to the methodology described in Section 5.1.2.3, Dispersion Modeling. 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 California Ambient Air Quality Standards (CAAQS) and National Ambient Air Quality Standards (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 5.1.2.3 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 5.1.1.2, Existing Air Quality. The resulting total pollutant concentrations were then compared with the most stringent CAAQS or NAAQS.

Construction Impacts

Section 5.1.2.1, Construction Emissions, described that Month 21 of the construction schedule was identified as the worst-case emission conditions for the purpose of analyzing peak short-term impacts to local air quality. Annual impacts were modeled with all emissions that would occur during the 12 months of construction from month 17 to month 28, since this period will have a higher intensity of construction activity than any subsequent part of the schedule.

Worst-case modeling was conducted for short-term averaging times using all construction equipment from Month 21 (the worst month). Annual (12-month) emissions were modeled for Months 17 through 28 of the construction schedule. These Project construction results of the modeling are presented in Table 5.1-34, Maximum Modeled Criteria Pollutant Impacts Due to Construction Emissions.

Table 5.1-34
Maximum Modeled Criteria Pollutant Impacts Due to Construction Emissions

Pollutant	Averaging Period	Maximum Modeled Impact (μg/m^3)	Background[1] (μg/m^3)	Maximum Total Predicted Concentration (μg/m^3)	Most Stringent AAQS (μg/m^3)	UTM Coordinates	
						East (m)	North (m)
Construction Impacts							
CO	1 hour	130.14	4025	4,155	23,000	292,199	3,911,835
	8 hour	31.19	2444	2,475	10,000	282,024	3,911,946
NO_2	1 hour[2]	39.29	190.1	229.4	339	282,461	3,913,059
	Annual[2]	0.65	39.6	40.33	57	282,675	3,911,638
PM_{10}	24 hour	27.69	267.4[3]	295.1	50	282,508	3,913,081
	Annual	0.34	56.5[3]	56.84	20	282,675	3,911,638
$PM_{2.5}$	24 hour	5.94	154[3]	160.0	35	282,508	3,913,081
	Annual	0.28	25.2[3]	25.48	12	282,675	3,911,638
SO_2	1 hour	0.28	340.6	340.9	655	282,199	3,911,835
	3 hour	0.18	195	195.2	1,300	282,024	3,911,946
	24 hour	0.026	81.38	81.41	105	282,024	3,911,946
	Annual	0.005	26.7	26.7	80	282,675	3,911,638

Source: HECA Project

Notes:
1 Background represents the maximum values, measured 2005 through 2008.
2 Results for NO_2 during construction used ozone limiting method (OLM) with ambient O_3 data.
3 PM_{10} and $PM_{2.5}$ background levels exceed ambient standards.
μg/m^3 = micrograms per cubic meter
AAQS = Ambient Air Quality Standard
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

As reflected in the construction modeling results presented in Table 5.1-34, Maximum Modeled Criteria Pollutant Impacts Due to Construction Emissions, high PM_{10} and $PM_{2.5}$ background concentrations have been recorded frequently at representative monitoring stations during recent years. Because of the land use characteristics of this area, it is highly probable that these conditions result primarily from high wind episodes and mobile pollution sources. The predicted contribution of the construction activities will be minor by comparison with these sources, but will have the potential to temporarily contribute to existing violations of the state and federal PM_{10} and $PM_{2.5}$ standards if construction occurs during a period of high background concentrations.

AERMOD with OLM predicted maximum 1-hour and annual NO_2 concentration due to Project construction emissions, which are below the 1-hour California standard when added to conservative background values from the nearest monitoring stations. Predicted maximum impacts for CO and SO_2 are also less than the most stringent ambient standards.

Operational Impacts

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 5.1-35, 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 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 5.1-35, 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 NAAQS, and will not significantly contribute to the existing violations of the federal and state PM_{10} and $PM_{2.5}$ standards. In addition, as described later, all of the Project's operational emissions of non-attainment pollutants and their precursors will be offset to ensure a net air quality benefit.

The locations of predicted maximum impacts will vary by pollutant and averaging time. Figure 5.1-3, 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.

Table 5.1-35
AERMOD Modeling Results for Project Operations (All Project Sources Combined)

Pollutant	Averaging Period	2000 (µg/m³)	2001 (µg/m³)	2002 (µg/m³)	2003 (µg/m³)	2004 (µg/m³)	Max (µg/m³)	Class II Significance Level (µg/m³)	% of SIL	Background Conc.[5] (µg/m³)	Monitoring Station Description[5]	CAAQS (µg/m³)	NAAQS (µg/m³)	Total Conc. (µg/m³)
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]	1,231.13	1,133.15	1,422.59	1,053.30	1,091.04	**1,422.59**	2,000	71%	4,025	2	23,000	40,000	5,448
	8-hour [6]	213.28	169.18	187.52	181.40	151.98	**213.28**	500	43%	2,444	2	10,000	10,000	2,657
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
PM_{10}	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	–
$PM_{2.5}$ [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	–

Table 5.1-35
AERMOD Modeling Results for Project Operations (All Project Sources Combined)

Pollutant	Averaging Period	2000 (µg/m^3)	2001 (µg/m^3)	2002 (µg/m^3)	2003 (µg/m^3)	2004 (µg/m^3)	Max (µg/m^3)	Class II Significance Level (µg/m^3)	% of SIL	Background Conc.[5] (µg/m^3)	Monitoring Station Description[5]	CAAQS (µg/m^3)	NAAQS (µg/m^3)	Total Conc. (µg/m^3)
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. Auxiliary Boiler does not operate with HRSG at the same time for short-term average period. Therefore, the Auxiliary 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:
CARB, Maximum of last 3 years (2006 – 2008), Bakersfield Golden State Highway, 2006
CARB, Maximum of last 3 years (2006 – 2008), Bakersfield Golden State Highway, 2007
CARB, Maximum of last 3 years (2006 – 2008), Bakersfield Golden State Highway, 2008
CARB, Maximum of last 3 years (2006 – 2008), Shafter-Walker Street, 2007
CARB, Maximum of last 3 years (2006 – 2008), Fresno – 1st Street, 2007
[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
CAAQ	=	California Ambient Air Quality
CO	=	carbon monoxide
H_2S	=	hydrogen sulfide
NAAQ	=	National Ambient Air Quality
NO_2	=	nitrogen dioxide
OLM	=	ozone limiting method
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

Carbon monoxide impacts from the carbon dioxide vent were predicted to be 2,934 $\mu g/m^3$ 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.

Hydrogen sulfide impacts from the carbon dioxide vent were predicted to be 35.84 $\mu g/m^3$ 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 $\mu g/m^3$.

Fumigation

The predicted peak concentrations from inversion fumigation from Project emissions, including background, are predicted to be below the CAAQS, and are as follows:

- NO_x 1-hour = 271.73 $\mu g/m^3$
- SO_2 1-hour = 32.91 $\mu g/m^3$
- SO_2 3-hour = 21.77 $\mu g/m^3$
- CO 1-hour = 5,236.56 $\mu g/m^3$

Turbine Commissioning

The Project turbines operated with partially abated emissions for purposes of commissioning. The expected sequence of commissioning tests and the associated emissions during each stage of each CTG commissioning are presented in Section 5.1.2.2, Operational Emissions. Separate modeling was conducted using AERMOD to evaluate maximum short-term effects of these activities in terms of the impacts on off-site 1-hour NO_2 concentrations, and 1-hour and 8-hour CO concentrations. These are the pollutants (along with VOCs, which are not modeled) for which emissions will be expected to be significantly higher than during normal operations, owing to the non-operability of the SCR and oxidation catalyst emission control systems during some of the commissioning tests. Emissions of SO_X and particulate matter depend primarily on the rate of fuel combustion and are unaffected by the availability or non-availability of the SCR and oxidation catalyst. Thus, emissions of these pollutants during commissioning are not expected to exceed the levels that will occur during full-load normal operations of the turbines, and separate modeling for commissioning impacts on SO_X and particulate matter levels is unnecessary.

Table 5.1-36, Commissioning Modeling Results, shows the results of the model simulations for the two phases of turbine commissioning. The tabulated impacts are the highest concentrations for the indicated averaging that are predicted by AERMOD to occur for the worst-case condition using 5 years of hourly meteorological input data. Table 5.1-36 demonstrates that when the maximum incremental commissioning impacts are added to applicable background concentrations and compared with the most stringent state or national ambient standards, no violations of the applicable standards for these pollutants are predicted to occur.

Impacts from commissioning were modeled with AERMOD, based on the emissions from the auxiliary CTG and the CTG/HRSG unit during commissioning, as described previously. The results from the commissioning modeling are presented below in Table 5.1-36, Commissioning Modeling Results.

Table 5.1-36
Commissioning Modeling Results

Modeling Scenario	Pollutant	Averaging Period	Maximum Estimated Impact ($\mu g/m^3$)	Background[1] ($\mu g/m^3$)	Total Predicted Concentration ($\mu g/m^3$)	Most Stringent Standard ($\mu g/m^3$) [2]
Auxiliary CTG commissioning only	CO	1 hour	213.9	4,025	4,238.9	23,000
		8 hours	46.7	2,444	2,490.7	10,000
	NO_2[3]	1 hour	56.3	190.1	246.4	339
Auxiliary CTG and Auxiliary Boiler running in normal operating mode, HRSG Commissioning (no other sources operating)	CO	1 hour	1,827.8	4,025	5,852.8	23,000
		8 hours	335.4	2,444	2,779.4	10,000
	NO_2[3]	1 hour	120.9	190.1	311.0	339

Source: HECA Project

Notes:
[1] Background represents the maximum values measured at the monitoring stations presented in Modeling Protocol.
[2] In February 2007, the CARB approved new, more stringent CAAQS for NO_2. The new standards of 339 $\mu g/m^3$ (1 hour) and 57 $\mu g/m^3$ (annual) became effective in March 2008.
[3] NO_2 modeling for commissioning was conducted with the OLM algorithm.
CO = carbon monoxide
$\mu g/m^3$ = micrograms per cubic meter
NO_2 = nitrogen dioxide

Impacts for Non-Attainment Pollutants and their Precursors

The emission offset program described in the SJVAPCD Rules and Regulations was developed to facilitate net air quality improvement when new sources locate within the District. Project impacts of non-attainment pollutants (PM_{10}, $PM_{2.5}$, and O_3) and their precursors (NO_X, SO_2, and VOC) will be fully mitigated by emission offsets. The emission reductions associated with these offsets have not been accounted for in the modeled impacts noted above. Thus, the impacts indicated in the foregoing presentation of model results for the Project may be significantly overestimated.

Effects on Visibility from Plumes

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. However, the generally warm, dry conditions in Kern County are not conducive to lengthy visible stack plumes. A visible plume analysis was performed for the Project. The methodology and results are discussed in Section 5.11, Visual Resources.

5.1.2.5 Impact on Air Quality-Related Values in 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-kilometer 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 kilometers) 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 C4. 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 kilometers) from the Project Site. Therefore, these two Class I areas do not meet the criterion of being within 62.1 miles (100 kilometers) and will not be included in this analysis. The nearest parts of the San Rafael Wilderness are located beyond 31.1 miles (50 kilometers) and within 62.1 miles (100 kilometers) 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 5.1-37, PSD Class I Increment Significance Analysis – CALPUFF Results. No Class I PSD increments will be exceeded.

Table 5.1-37
PSD Class I Increment Significance Analysis – CALPUFF Results

Class I Area	Pollutant Unit Threshold	Annual NO_x µg/m^3 0.1	3-hour SO_2 µg/m^3 1	24-hour SO_2 µg/m^3 0.2	Annual SO_2 µg/m^3 0.08	24-hour PM_{10} µg/m^3 0.32	Annual PM_{10} Annual 0.16
San Rafael Wilderness Area	2001	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

Source: HECA Project

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

Effects on Visibility. 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 U.S. Forest Service (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 10 percent extinction change. Visibility impact results for the San Rafael Wilderness Class I area are shown in Table 5.1-38, Visibility Analysis – CALPUFF Results. No maximum extinction change exceeds 10 percent, with only 2 to 4 days of exceedance of 5 percent despite the conservative operating scenario. A detailed description of the conservative modeling scenario is contained in Appendix C4. Therefore, the Project screening successfully passed all screening criteria.

Table 5.1-38
Visibility Analysis – CALPUFF Results

Class I Area	Pollutant Unit Threshold	No. of Days > 5% Days 0	No. of Days >10% Days 0	Maximum Extinction Change % 5	Day of Maximum Extinction Change Day
San Rafael Wilderness Area	2001	2	0	9.64	308
	2002	4	0	8.09	287
	2003	2	0	6.58	247
Exceed?				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 5.1-39, 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 5.1-39
Total Nitrogen and Sulfur Deposition Analysis – CALPUFF Results

Class I Area	Pollutant Unit Threshold	Deposition Nitrogen $g/m^2/s$ 1.59E-11	Deposition Sulfur $g/m^2/s$ 1.59E-11
San Rafael Wilderness Area	2001	1.04E-12	4.23E-13
	2002	1.30E-12	5.57E-13
	2003	1.32E-12	4.97E-13
Exceed?		No	No

Source: HECA Project

Note:
$g/m^2/s$ = 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.

5.1.3 Cumulative Impacts Analyses

CEC requirements specify that an analysis may be required to determine the cumulative impacts of the Project and other Projects within a 6-mile radius that have received construction permits but are not yet operational or that are in the permitting process. The cumulative impact analysis is intended to assess whether the emissions of the combined effects of these sources may cause or contribute to a violation of any AAQS.

The Applicant has obtained a list of projects within a 6-mile radius from the Project from the SJVAPCD. (See Appendix J, List of Proposed Projects.) These projects will be analyzed in a cumulative impact analysis. The results of the final cumulative impact analysis will be reported under separate cover.

5.1.4 Mitigation Measures

In accordance with the PSD regulations, CEC rules, as well as the requirements of SJVAPCD rules, the Project is required to provide emission offsets in the form of emissions reduction credits (ERC) for increases in emissions of non-attainment pollutants in excess of specified thresholds that will result from the operation of the Project on a pollutant-specific basis. A detailed mitigation measure via ERC discussion is presented in Appendix T.

5.1.5 Laws, Ordinances, Regulations, and Standards

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

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

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

Applicable LORS related to the potential air quality impacts from the Project are described below, and shown in Table 5.1-40, Laws, Ordinances, Regulations, and Standards – Air Quality. These LORS are administered (either independently or cooperatively) by the SJVAPCD, USEPA Region IX, the CEC, and CARB. The area of responsibility for each of these agencies is described below.

5.1.5.1 Ambient Air Quality Standards

USEPA, in response to the federal CAA of 1970, established federal AAQS in Title 40 CFR Part 50. The federal AAQS include both primary and secondary standards for six "criteria" pollutants. These criteria pollutants are O_3, CO, NO_2, SO_2, PM_{10}, and 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 federal AAQS. In addition to the federal AAQS described above, a new federal standard for $PM_{2.5}$ and a revised O_3 standard were promulgated in July 1997. The new federal standards were challenged in a court case during 1998. The court required revisions in both standards before USEPA can enforce them. The U.S. Supreme Court upheld an appeal of the District Court decision in February 2001. These issues were resolved and the 1-hour O_3 standard revoked in 2005, while the revised $PM_{2.5}$ standard was made effective in 2006. The state of California has adopted CAAQS that are in some cases more stringent than the federal AAQS. The state and federal AAQS relevant to the Project are summarized in Table 5.1-41, Relevant Ambient Air Quality Standards.

Table 5.1-40
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 IX
CAA 171-193, 42 USC 7501 et seq. (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of stationary sources. NSR applies to pollutants for which ambient concentrations are higher than NAAQS.	USEPA Region IX
CAA 401 (Title IV), 42 USC 7651 (Acid Rain Program); SJVAPCD Regulation IV, Rule 2540	Requires reductions in NO_X and SO_2 emissions.	SJVAPCD, with USEPA Region IX oversight
CAA 501 (Title V), 42 USC 7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	SJVAPCD, with USEPA Region IX oversight
CAA 111, 42 USC 7411, 40 CFR Part 60 (New Source Performance Standards, or NSPS)	Establishes national standards of performance for new stationary sources. This rule incorporates the New Source Performance Standards from Part 60, Chapter 1, Title 40, CFR.	SJVAPCD, with USEPA Region IX oversight
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

Table 5.1-40
Laws, Ordinances, Regulations, and Standards – Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
California Public Resources Code 25523(a); 20 CCR 1752, 2300 2309 and Div. 2, Chap. 5, Art. 1, Appendix B, Park (k) (CEC and CARB Memorandum of Understanding)	Requires that CEC's decision on the AFC includes requirements to assure protection of environmental quality; AFC is required to address air quality protection.	CEC
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. (b) [not presented in this report because it pertains to biomass fuels and does not affect the Project] (c) For covered procurements that employ geological formation injection for CO_2 sequestration, the annual average 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 based on projections of net emissions over the life of the power plant. Carbon dioxide emissions shall be considered successfully sequestered if the sequestration project meets the following requirements: (1) Includes the capture, transportation, and geologic formation injection of CO_2 emissions; (2) Complies with all applicable laws and regulations; and (3) Has an economically and technically feasible plan that will result in the permanent sequestration of CO_2 once the sequestration project is operational.	CARB

Table 5.1-40
Laws, Ordinances, Regulations, and Standards – Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
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
SJVAPCD Regulation II, Rule 2520	The purpose of this rule is to provide for the following: 1.1 An administrative mechanism for issuing operating permits for new and modified sources of air contaminants in accordance with requirements of 40 CFR Part 70. 1.2 An administrative mechanism for issuing renewed operating permits for sources air contaminants in accordance with requirements of 40 CFR Part 70. 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. 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. 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, Code of Federal Regulations (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

Table 5.1-40
Laws, Ordinances, Regulations, and Standards – Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
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, Code of Federal Regulations (CFR) and the National Emission Standards for Hazardous Air Pollutants for Source Categories from Part 63, Chapter I, Subchapter C, Title 40, Code of Federal Regulations (CFR).	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
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 0.1 grains/scf of gas at dry standard conditions.	SJVAPCD
SJVAPCD Regulation IV, Rule 4202	Particulate Matter Emission - this rule provides a table 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 (NO_x) and carbon monoxide (CO).	SJVAPCD
SJVAPCD Regulation IV, Rule 4305-4308	The purpose of this rule is to limit emissions of nitrogen oxides (NO_x) and carbon monoxide (CO) from boilers, steam generators, and process heaters.	SJVAPCD
SJVAPCD Regulation IV, Rule 4311	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 rated brake horsepower greater than 50 horsepower.	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 percent by volume calculated as SO_2	SJVAPCD

Table 5.1-40
Laws, Ordinances, Regulations, and Standards – Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
SJVAPCD Regulation VIII	The purpose of Regulation VIII (Fugitive PM_{10} Prohibitions) is to reduce ambient concentrations of fine particulate matter (PM_{10}) by requiring actions to prevent, reduce or mitigate anthropogenic fugitive dust emissions. The Rules contained in this Regulation have been developed pursuant to U.S. Environmental Protection Agency guidance for Serious PM_{10} Nonattainment Areas. The rules are applicable to specified anthropogenic fugitive dust sources. Fugitive dust contains PM_{10} and particles larger than PM_{10}. Controlling fugitive dust emissions when visible emissions are detected will not prevent all PM_{10} emissions, but will substantially reduce PM_{10} emissions.	SJVAPCD
SJVAPCD Regulation IX	This Rule specifies the criteria and procedures for determining the conformity of federal actions with the San Joaquin Valley Air Pollution Control District's air quality implementation plan.	SJVAPCD
Industry		
None Applicable	None Applicable	

Table 5.1-41
Relevant Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS[1] Primary[3,4]	NAAQS[1] Secondary[3,5]	CAAQS[2] Concentration[3]
Ozone	1-Hour	Revoked [8]	Same as Primary Standard	0.09 ppm (180 µg/m³)
	8-Hour	0.075 ppm		0.07 ppm (137 µg/m³)
Carbon Monoxide	8-Hour	9 ppm (10 mg/m³)	None	9.0 ppm (10 mg/m³)
	1-Hour	35 ppm (40 mg/m³)		20 ppm (23 mg/m³)
Nitrogen Dioxide [9]	Annual Average	0.053 ppm (100 µg/m³)	Same as Primary Standard	0.030 ppm (57 µg/m³)
	1-Hour	–		0.18 ppm (339 µg/m³)
Sulfur Dioxide	Annual Average	0.03 ppm (80 µg/m³)	–	–
	24-Hour	0.14 ppm (365 µg/m³)	–	0.04 ppm (105 µg/m³)
	3-Hour	–	0.5 ppm (1,300 µg/m³)	–
	1-Hour	–	–	0.25 ppm (655 µg/m³)
Suspended Particulate Matter (PM_{10})	24-Hour	150 µg/m³	Same as Primary Standard	50 µg/m³
	Annual Arithmetic Mean	Revoked [6]		20 µg/m³
Fine Particulate Matter ($PM_{2.5}$) [7]	24-Hour	35 µg/m³	Same as Primary Standard	–
	Annual Arithmetic Mean	15 µg/m³		12 µg/m³
Lead	30-Day Average	–	–	1.5 µg/m³
	Quarterly Average	1.5 µg/m³	Same as Primary Standard	–
Hydrogen Sulfide	1-Hour	No Federal Standards		0.03 ppm (42 µg/m³)
Sulfates	24-Hour			25 µg/m³
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: USEPA-NAAQS (http://www.epa.gov/air/criteria.html); CARB-CAAQS (http://www.arb.ca.gov/aqs/aaqs2.pdf)

Notes:

1. National standards (other than ozone, particulate matter, and those based on annual 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 µg/m³ 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 µg/m³ (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.

µg/m³	=	micrograms per cubic meter	NAAQS	=	National Ambient Air Quality Standards
CAAQS	=	California Ambient Air Quality Standards	ppm	=	parts per million [3]
mg/m³	=	milligram per cubic meter			

USEPA, CARB, and the local air pollution control districts determine air quality attainment status by comparing local ambient air quality measurements from the state or local ambient air monitoring stations with the federal and 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, H_2S, and SO_2, and non-attainment for O_3, PM_{10}, and $PM_{2.5}$. Nitrogen dioxide and SO_2 are regulated as PM_{10} precursors, and NO_2 and VOCs as O_3 precursors. Table 5.1-42, Attainment Status for Kern County with Respect to Federal and California Ambient Air Quality Standards, presents the attainment status (both federal and state) for SJVAB.

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

Table 5.1-42
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 25 September 2008, USEPA redesignated the San Joaquin Valley to attainment for the PM_{10} National Ambient Air Quality Standard (NAAQS) and approved the PM_{10} Maintenance Plan.
CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
SO_2 = sulfur dioxide

5.1.5.2 Prevention of Significant Deterioration Requirements

In addition to the AAQS described above, the federal PSD program has been established to protect deterioration of air quality in those areas that already meet NAAQS. The PSD program specifies allowable 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 significant emission PSD triggers for CO, SO_2, NO_X, PM_{10}, VOCs, and Pb are as shown in Table 5.1-43, 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 5.1-44, Prevention of Significant Deterioration Allowable Increments ($\mu g/m^3$). 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 5.1-43
PSD Emission Threshold Triggers for New Stationary Sources

Pollutant	Significant 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
VOCs = volatile organic compounds

Table 5.1-44
Prevention of Significant Deterioration Allowable Increments
($\mu g/m^3$)

Standard	Class I Area	Class II Area	Class III Area
PM_{10} Annual Arithmetic Mean	4	17	34
PM_{10} 24-Hour Maximum	8	30	60
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.

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

5.1.5.3 Acid Rain Program Requirements

Title IV of the CAAA applies to sources of air pollutants that contribute to acid rain formation, including certain sources of SO_2 and NO_X emissions. The SJVAPCD has been delegated the authority by USEPA to administer Title IV requirements under its Title V Operating Permit program in Regulation II. Title IV is implemented by USEPA under 40 CFR 72, 73, and 75. The Acid Rain Program provisions of 40 CFR Part 72, Subparts A through I, are incorporated in SJVAPCD Rule 2540. Allowances of SO_2 emissions are set aside in 40 CFR 73. Sources subject to Title IV are required to obtain SO_2 allowances, to monitor their emissions, and obtain SO_2 allowances when a new source is permitted. Sources such as the Project that use 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; 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 CEMSs.

5.1.5.4 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 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 are further discussed in the BACT section (Appendix D).

5.1.5.5 Federally Mandated Operating Permits

Title V of the CAAA requires USEPA to develop a federal operating permit program that is implemented under 40 CFR 70. This program is administered by SJVAPCD under 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.

5.1.5.6 California Power Plants Siting Requirements

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

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

5.1.5.7 Air Toxic "Hot Spots" Program

As required by the California Health and Safety Code §44300, all facilities with criteria air pollutant emissions in excess of 10 tons per year are required to submit air toxic "Hot Spots" emissions information. The operational Project will be required to provide quantitative information to the SJVAPCD on the Project's emissions of toxic air contaminants. This requirement is applicable only after the start of operation. Section 5.16, Public Health, demonstrates that the Project's emissions of toxic air contaminants impacts from the Project will be less than significant.

5.1.5.8 Determination of Compliance, Authority to Construct, and Permit to Operate

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

5.1.5.9 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.

5.1.5.10 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.

Section 4.1, BACT. An Applicant must apply BACT to any new or modified emissions unit that has a potential to emit 2.0 pounds per day or more of any pollutant. The SJVAPCD maintains a list of current BACT standards for specific source categories, which is posted on the District's website. Appendix D-2 provides a formal BACT evaluation for the Project. The proposed BACT levels for the Project turbines are shown in Table 5.1-45, Proposed BACT for the Project.

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 levels shown in Appendix T Mitigation Measures – Emissions Offsets. Appendix T describes the methods for determining the quantities of emission reduction credits needed to offset emissions from the Project. The discussion includes information on the required offset amounts for the Project and on the progress to date in obtaining the required numbers of ERCs.

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.

Table 5.1-45
Proposed BACT for the Project

Pollutant	Technology	Emission Limit
CTG/HRSG Combustion Turbine (excluding Startup/Shutdown conditions)		
NO_x	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 fuel) ≤ 0.75 grain / 100 SCF (12.65 ppm for natural gas)
VOCs	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	2.5 ppm NO_x @ 15% O_2 on natural-gas fuel, 3-hour average
	Selective Catalytic Reduction	
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)
VOCs	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		
NO_x	Low NO_x Burner with FGR	9 ppm NOx @ 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)
VOCs		0.004 lb/MMBtu heat input

Table 5.1-45
Proposed BACT for the Project

Pollutant	Technology	Emission Limit
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
VOCs		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
VOCs		0.14 g/Bhp/hr
Gasification Flare		
NO_x, CO, PM/PM_{10}, SO_2, VOC	GCP, gaseous fuel only, gas cleanup/limit on reduced sulfur in syngas	
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
VOCs	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	
VOCs	GCP	

Table 5.1-45
Proposed BACT for the Project

Pollutant	Technology	Emission Limit
CO_2 Vent		
CO	Gas Cleanup	1,000 ppmv
VOCs	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)
VOCs	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 in diameter
ppm = parts per million
ppmvd = parts per million volumetric dry
SCF = standard cubic feet
SO_2 = sulfur dioxide
VOCs = volatile organic compounds

As described in Section 5.2.2.4, Modeling Results – 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 (NOI) 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 is returned to the Applicant for re-submittal.

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

Rule 2520, Federally Mandated Operating Permits

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

Rule 3010/3020, Permit Fees

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

Rule 3110, Air Toxics Fees

This rule applies to facilities subject to the requirements of the Air Toxics “Hot Spots” Information and Assessment Act (§§ 44340 and 44383 of the California Health and Safety Code) and to facilities subject to 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 VOCs. The fees required pursuant to this section are additional to the permit fees and other fees required under other Rules and Regulations. This rule will cease to be effective when the Administrator of USEPA designates the SJVAPCD to be in attainment of the federal 1-hour standard for O_3. The Project will be a major source under either the federal or SJVAPCD definitions, and is subject to Rule 3170.

Rule 4001, New Source Performance Standards

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

Rule 4002, National Emission Standards for Hazardous Air Pollutants

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

Rule 4101, Visible Emissions

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

Rule 4102, Nuisance

This rule states that there shall be no discharge of such quantities of any pollutant or material 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 grain per dry standard cubic foot of natural gas as determined by the following test methods: Particulate matter concentration – USEPA Method 5; Stack gas velocity – USEPA Method 2; Stack gas moisture – USEPA Method 4. The Project natural gas turbines will easily comply with this requirement, with a maximum PM_{10} emission rate of approximately 0.045 grain 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 grain 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 Methods 1 through 100.

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

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

Rule 8041, Carryout and Trackout

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

Rule 8051, Open Areas

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

Rule 8061, Paved and Unpaved Roads

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

Rule 8071, Unpaved Vehicle/Equipment Traffic Areas

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

5.1.6 Involved Agencies and Agency Contacts

Agencies and individuals contacted in connection with the air quality assessment of the Project are detailed in Table 5.1-46, Involved Agencies and Agency Contacts.

Table 5.1-46
Involved Agencies and Agency Contacts

Agency	Contact/Title	Telephone
California Energy Commission	Keith Golden Air Quality Specialist 1516 Ninth Street Sacramento, CA 95814	(916) 654-4287
California Air Resources Board	Mike Tollstrup 1001 I Street Sacramento, CA 95814	(916) 322-6026
San Joaquin Valley Air Pollution Control District	Leonard Scandura Supervising Air Quality Engineer 34946 Flyover Court Bakersfield, CA 93308	(661) 392-5601
U.S. Environmental Protection Agency	Gerardo Rios Chief, Permits Office 75 Hawthorne St. San Francisco, CA 94105	(415) 972-3974

5.1.7 Permits Required and Permit Schedule

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.

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

5.1.8 References

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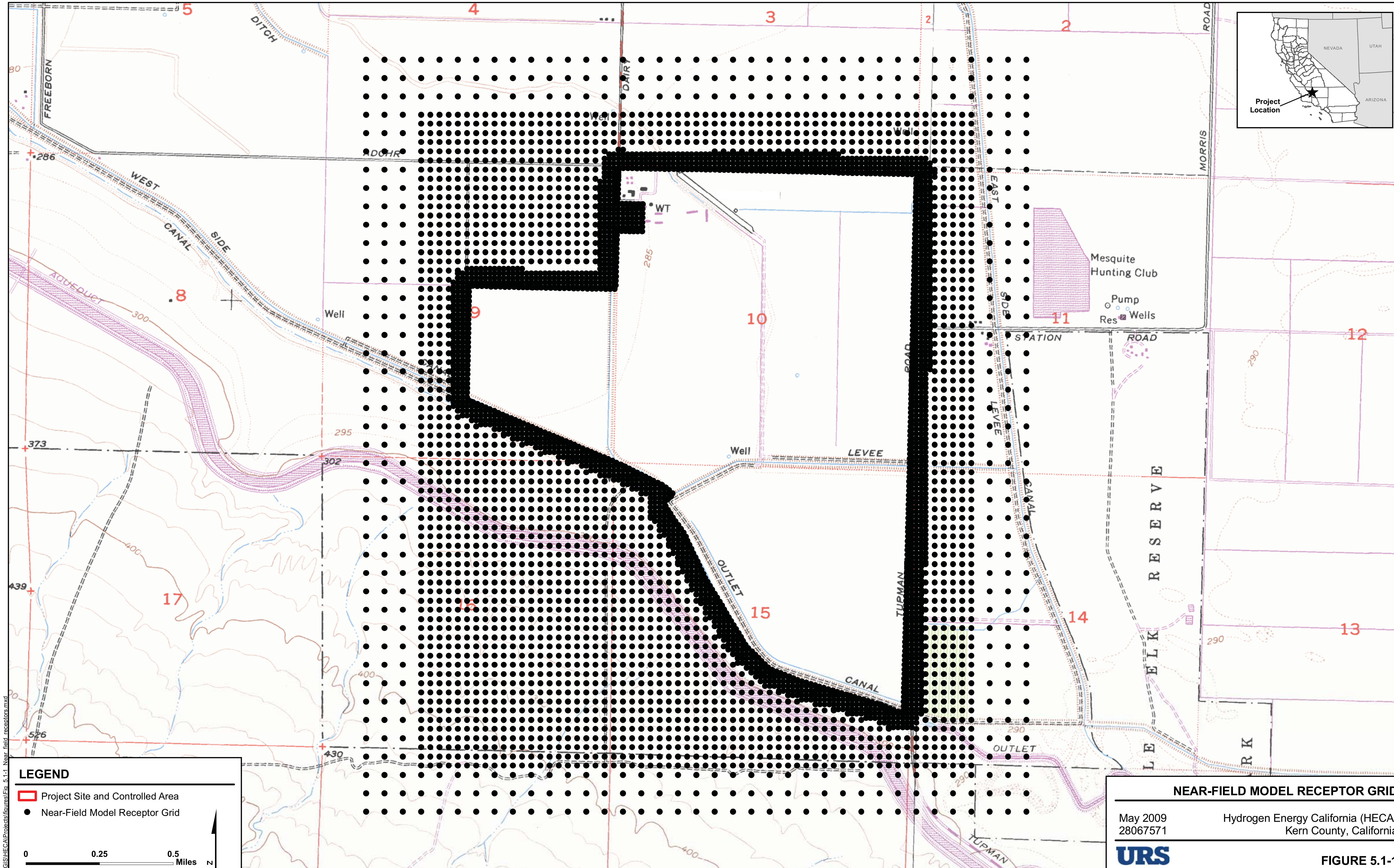

LEGEND

- Project Site and Controlled Area
- Near-Field Model Receptor Grid

0 0.25 0.5 Miles

N

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NEAR-FIELD MODEL RECEPTOR GRID

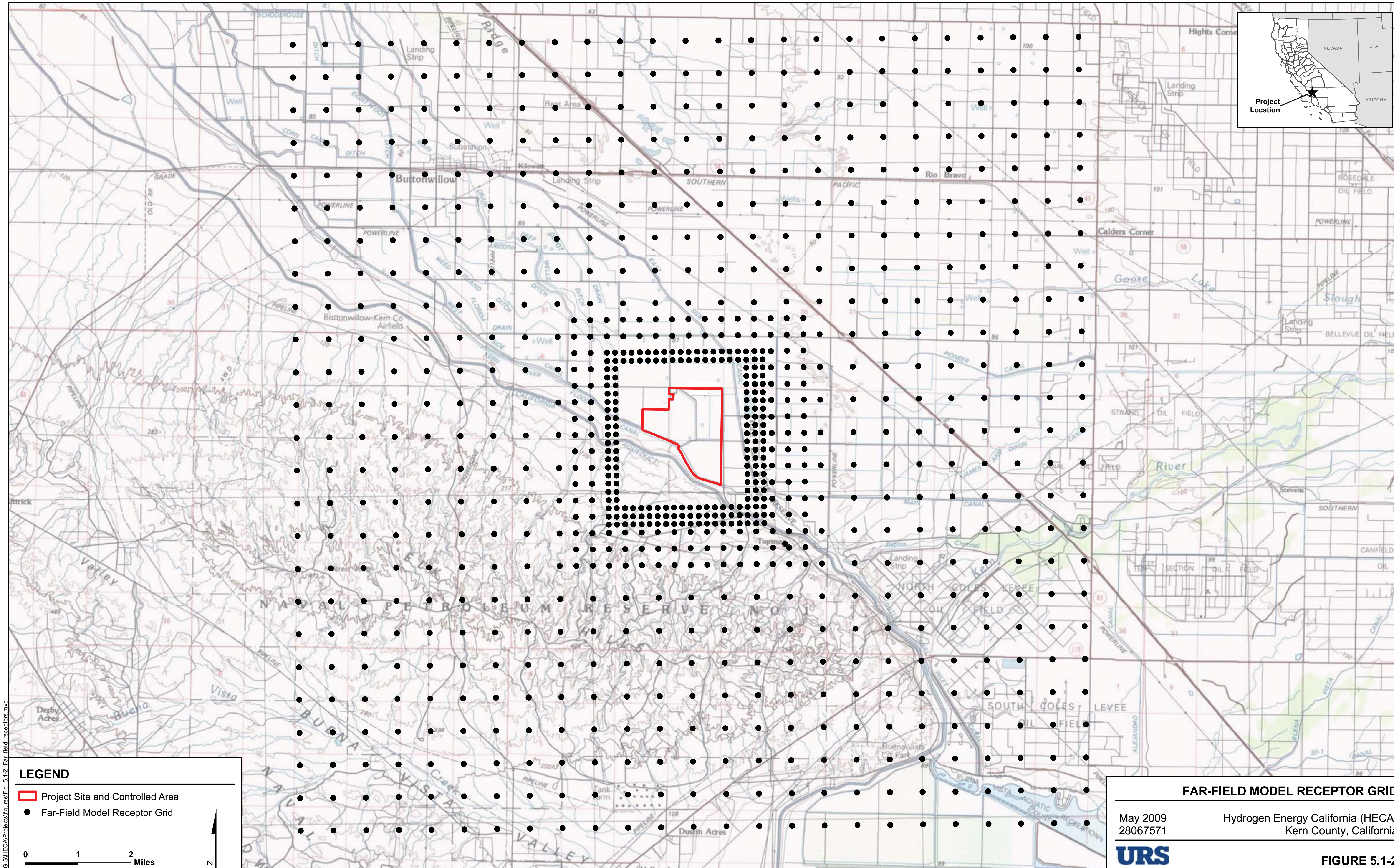
May 2009
28067571

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 5.1-1

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

FIGURE 5.1-2

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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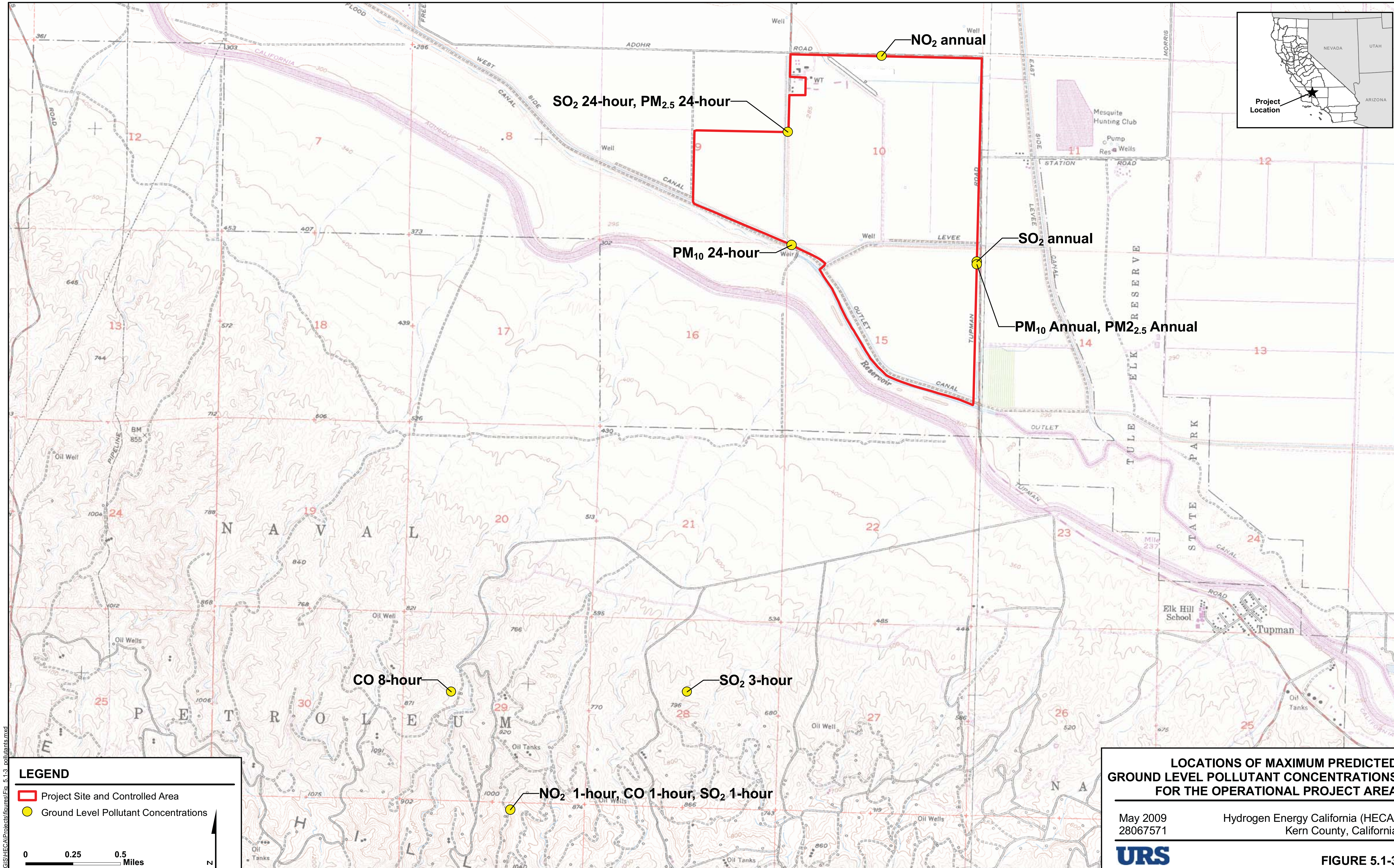

LOCATIONS OF MAXIMUM PREDICTED GROUND LEVEL POLLUTANT CONCENTRATIONS FOR THE OPERATIONAL PROJECT AREA

May 2009
28067571

Hydrogen Energy California (HECA)
Kern County, California

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FIGURE 5.1-3

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).

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Technical Area: **Air Quality** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

Siting Regulations	**Information**	**AFC Page Number And Section Number**	**Adequate Yes Or No**	**Information Required To Make AFC Conform With Regulations**
Appendix B (g) (1)	...provide a discussion of the existing site conditions, the expected direct, indirect and cumulative impacts due to the construction, operation and maintenance of the project, the measures proposed to mitigate adverse environmental impacts of the project, the effectiveness of the proposed measures, and any monitoring plans proposed to verify the effectiveness of the mitigation.	Section 5.1, p. 5.1-1		
Appendix B (g) (8) (A)	The information necessary for the air pollution control district where the project is located to complete a Determination of Compliance.	Section 5.1, p. 5.1-1		
Appendix B (g) (8) (B)	The heating value and chemical characteristics of the proposed fuels, the stack height and diameter, the exhaust velocity and temperature, the heat rate and the expected capacity factor of the proposed facility.	Table 2-4, p. 2-12 Table 2-5, p. 2-13 Table 2-6, p. 2-13 Table 2-7, p. 2-15 Table 2-9, p. 2-18 Appendix D		
Appendix B (g) (8) (C)	A description of the control technologies proposed to limit the emission of criteria pollutants.	Appendix D Table 5.1-45, p. 5.1-86		
Appendix B (g) (8) (D)	A description of the cooling system, the estimated cooling tower drift rate, the rate of water flow through the cooling tower, and the maximum concentrations of total dissolved solids.	Section 2.4.7, p. 2-43		

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Appendix B (g) (8) (E)	The emission rates of criteria pollutants and greenhouse gases (CO2, CH4, N2O, and SF6) from the stack, cooling towers, fuels and materials handling processes, delivery and storage systems, and from all on-site secondary emission sources.	Table 5.1-20, p. 5.1-33		
Appendix B (g) (8) (F)(i)	A description of typical operational modes, and start-up and shutdown modes for the proposed project, including the estimated frequency of occurrence and duration of each mode, and estimated emission rate for each criteria pollutant during each mode.	Table 5.1-11, p. 5.1-20 Table 5.1-12, p. 5.1-21 Table 5.1-13, p. 5.1-23 Table 5.1-14, p. 5.1-24 Table 5.1-15, p. 5.1-25, Table 5.1-17, p. 5.1-27 Table 5.1-18, p. 5.1-28 Table 5.1-19, p. 5.1-29		
Appendix B (g) (8) (F)(ii)	A description of the project's planned initial commissioning phase, which is the phase between the first firing of emissions sources and the commercial operations date, including the types and durations of equipment tests, criteria pollutant emissions, and monitoring techniques to be used during such tests.	Section 5.1.2.2, p. 5.1-18 Table 5.1-21, p. 5.1-38 Table 5.1-22, p. 5.1-41 Table 5.1-23, p. 5.1-43		

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SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (g) (8) (G)	The ambient concentrations of all criteria pollutants for the previous three years as measured at the three Air Resources Board certified monitoring stations located closest to the project site, and an analysis of whether this data is representative of conditions at the project site. The applicant may substitute an explanation as to why information from one, two, or all stations is either not available or unnecessary.	Section 5.1.1.2, p. 5.1-7 Table 5.1-3, p. 5.1-9 Table 5.1-4, p. 5.1-10 Table 5.1-5, p. 5.1-11 Table 5.1-6, p. 5.1-12 Table 5.1-7, p. 5.1-12 Table 5.1-8, p. 5.1-13		
Appendix B (g) (8) (H)	One year of meteorological data collected from either the Federal Aviation Administration Class 1 station nearest to the project or from the project site, or meteorological data approved by the California Air Resources Board or the local air pollution control district.	Included on DVD		
Appendix B (g) (8) (H) (i)	If the data is collected from the project site, the applicant shall demonstrate compliance with the requirements of the U.S. Environmental Protection Agency document entitled “On-Site Meteorological Program Guidance for Regulatory Modeling Applications” (EPA - 450/4-87-013 (August 1995)), which is incorporated by reference in its entirety.	Section 5.1.2.3, p. 5.1-54		

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Appendix B (g) (8) (H) (ii)	The data shall include quarterly wind tables and wind roses, ambient temperatures, relative humidity, stability and mixing heights, upper atmospheric air data, and an analysis of whether this data is representative of conditions at the project site.	Included on DVD		
Appendix B (g) (8) (I)	An evaluation of the project's direct and cumulative air quality impacts, consisting of the following:			
Appendix B (g) (8) (I) (i)	A screening level air quality modeling analysis, or a more detailed modeling analysis if so desired by the applicant, of the direct criteria pollutant impacts of project construction activities on ambient air quality conditions, including fugitive dust (PM_{10}) emissions from grading, excavation and site disturbance, as well as the combustion emissions [nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), and particulate matter less than 10 microns in diameter (PM_{10}) and particulate matter less than 2.5 microns in diameter (PM2.5)] from construction-related equipment;	Section 5.1.2.4, p. 5.1-62		

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Siting Regulations	**Information**	**AFC Page Number And Section Number**	**Adequate Yes Or No**	**Information Required To Make AFC Conform With Regulations**
Appendix B (g) (8) (I) (ii)	A screening level air quality modeling analysis, or a more detailed modeling analysis if so desired by the applicant, of the direct criteria pollutant (NO_x, SO_2, CO, $PM_{10,}$ and $PM_{2.5}$) impacts on ambient air quality conditions of the project during typical (normal) operation, and during shutdown and startup modes of operation. Identify and include in the modeling of each operating mode the estimated maximum emissions rates and the assumed meteorological conditions;	Section 5.1.2.4, p. 5.1-62		
Appendix B (g) (8) (I) (iii)	A protocol for a cumulative air quality modeling impacts analysis of the project's typical operating mode in combination with other stationary emissions sources within a six mile radius which have received construction permits but are not yet operational, or are in the permitting process. The cumulative inert pollutant impact analysis should assess whether estimated emissions concentrations will cause or contribute to a violation of any ambient air quality standard; and	Section 5.1.3, p. 5.1-71		
Appendix B (g) (8) (I) (iv)	An air dispersion modeling analysis of the impacts of the initial commissioning phase emissions on state and federal ambient air quality standards for $NO_{X,}$ SO_2, CO, PM_{10}, and $PM_{2.5}$.	Section 5.1.2.4, p. 5.1-62		
Appendix B (g) (8) (J)	If an emission offset strategy is proposed to mitigate the project's impacts under subsection (g)(1), provide the following information:			

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Appendix B (g) (8) (J) (i)	The quantity of offsets or emission reductions that are needed to satisfy air permitting requirements of local permitting agencies (such as the air district), state and federal oversight air agencies, and the California Energy Commission. Identify by criteria air pollutant, and if appropriate, greenhouse gas; and	Section 5.1.4, p. 5.1-72 Appendix T		
Appendix B (g) (8) (J) (ii)	Potential offset sources, including location, and quantity of emission reductions;	Appendix T		
Appendix B (g) (8) (K)	A detailed description of the mitigation, if any, which an applicant may propose, for all projects impacts from criteria pollutants that currently exceed state or federal ambient air quality standards, but are not subject to offset requirements under the district's new source review rule.	Section 5.1.4, p. 5.1-72 Appendix T		
Appendix B (i) (1) (A)	Tables which identify laws, regulations, ordinances, standards, adopted local, regional, state, and federal land use plans, leases, and permits applicable to the proposed project, and a discussion of the applicability of, and conformance with each. The table or matrix shall explicitly reference pages in the application wherein conformance, with each law or standard during both construction and operation of the facility is discussed; and	Section 5.1.5, p. 5.1-72		

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Appendix B (i) (1) (B)	Tables which identify each agency with jurisdiction to issue applicable permits, leases, and approvals or to enforce identified laws, regulations, standards, and adopted local, regional, state and federal land use plans, and agencies which would have permit approval or enforcement authority, but for the exclusive authority of the commission to certify sites and related facilities.	Section 5.1.6, p. 5.1-90 Table 5.1-46, p. 5.1-91		
Appendix B (i) (2)	The name, title, phone number, address (required), and email address (if known), of an official who was contacted within each agency, and also provide the name of the official who will serve as a contact person for Commission staff.	Table 5.1-46, p. 5.1-91		
Appendix B (i) (3)	A schedule indicating when permits outside the authority of the commission will be obtained and the steps the applicant has taken or plans to take to obtain such permits.	Section 5.1-7, p. 5.1-91		