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HYDROGEN ENERGY CALIFORNIA PROJECT

Preliminary Staff Assessment, Part I

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HYDROGEN ENERGY CALIFORNIA PROJECT
(08-AFC-8)
PRELIMINARY STAFF ASSESSMENT
PART 1

EXECUTIVE SUMMARY

Rod Jones

INTRODUCTION

This Preliminary Staff Assessment (PSA) contains the California Energy Commission staff's independent evaluation of the Hydrogen Energy California Power Plant project (HECA) Application for Certification (08-AFC-8). The PSA examines engineering, environmental, public health and safety aspects of the HECA project, based on the information provided by the applicant, the Hydrogen Energy International LLC, and other sources available at the time the PSA was prepared. The PSA contains analyses similar to those normally contained in an Environmental Impact Report (EIR) required by the California Environmental Quality Act (CEQA). When issuing a license, the Energy Commission is the lead state agency under CEQA, and its process is functionally equivalent to the preparation of an EIR.

The Energy Commission staff has the responsibility to complete an independent assessment of the project's engineering design and its potential effects on the environment, the public's health and safety, and whether the project conforms to all applicable laws, ordinances, regulations and standards (LORS). The staff also recommends measures to mitigate potential significant adverse environmental effects and conditions of certification for construction, operation and eventual closure of the project, if approved by the Energy Commission.

This PSA is not the decision document for these proceedings nor does it contain findings of the Energy Commission related to environmental impacts or the project's compliance with local/state/federal legal requirements. A 30-day public comment period is initiated with publication of the PSA. Staff will hold a workshop prior to completion of the PSA. The workshop is used to identify and resolve areas of disagreement or requiring additional information. After both parts of the PSA are issued and all outstanding matters resolved, staff will issue the Final Staff Assessment (FSA). The FSA will serve as staff's testimony in evidentiary hearings to be held by the Committee of two Commissioners who are overseeing this case. After evidentiary hearings, the Committee will consider the recommendations presented by staff, the applicant, all parties, government agencies, and the public in preparing its Presiding Member's Proposed Decision. At the completion of this process the full Energy Commission will make the final decision.

PROJECT LOCATION AND DESCRIPTION

The proposed HECA project would gasify petroleum coke (or blends of petroleum coke and coal, as needed) in its gasification block to produce hydrogen which will fuel a General Electric (GE) 7FB combustion turbine generator (CTG) operating in combined cycle mode. The CTG would produce 390 megawatts (MW) gross/250 MW net combined cycle power providing California with baseload power to the grid. The 140 MW difference results from the high parasitic load associated with the complex processes associated with the HECA facilities. The gasification block would also capture approximately 90% of the carbon from the raw syngas (the direct end of the gasification process involving the feedstock) at steady-state operation. The captured carbon dioxide (CO^2) would be transported via pipeline to a custody transfer point within the Elk Hills oil field for injection into the reservoir as part of an enhanced oil recovery (EOR) and CO^2 sequestration process.

The proposed project would be located on a 473-acre site (currently used for agricultural production of alfalfa, cotton, and onions), and is comprised of two parcels (Part of Assessor's Parcel # 159-040-16 and 159-040-18. The project site would be located in western unincorporated Kern County, approximately 1.5 miles northwest of the unincorporated community of Tupman. It is bounded by Adohr Road on the north, Tupman Road to the east, and the California State Water Project aqueduct to the south, and Dairy Road to the west. Adohr Road would provide primary access to the site. Most notably, Stockdale Highway and Interstate 5 are located approximately one mile to the north and three miles to the east, respectively, and the Elk Hills oil field is located approximately one mile south of the proposed project site. (See **Figure 1,** Project Vicinity).

Construction of the proposed HECA facility would require the use of five parcels totaling 139.1 acres, and designated as construction facilities and lay down areas. Project Description **Figures 2 & 3** show the project site – project rendering and preliminary temporary construction facilities plan including laydown areas which would be located inside the site boundary. During construction the five parcels would be separated by the following areas: Area No. 1(12 acres), Area No. 2 (36 acres), Area No. 3 (28 acres); Remote Laydown Area (56 acres) and Air Separation Unit Laydown Area (7.10 acres).

PUBLIC AND AGENCY COORDINATION

On July 31, 2008, Hydrogen Energy International, LLC (HEI) submitted an Application for Certification (AFC) to the California Energy Commission to construct and operate HECA. On May 28, 2009, HEI submitted a revised AFC that superseded and replaced the previously filed July 31, 2008 AFC in its entirety. On June 17, 2009, the Energy Commission staff sent notification letters, copies of the Revised AFC, for HECA to a comprehensive list of libraries and public agencies. Notice of Receipt letter was also sent to businesses organizations and residences located within 1,000 feet of the proposed project and 500 feet of the linear facilities. The Energy Commission staff's notification letter requested public and agency review, comment, and continued participation in the Energy Commission's certification process. In addition staff provides all documents to the

On July 15, 2009, the Energy Commission determined that the Hydrogen Energy California project did not meet all the requirements listed in Title 20, section 1704, and Division 2, Chapter 5. Appendix B of the California Code Regulations for the 12-month process. Specifically, the AFC was deficient in four of the 23 technical areas reviewed: air quality, biological resources, cultural resources, and transmission system design.

On July 13, 2009, HEI filed an AFC Data Adequate Supplement to the AFC containing the required information for review. Staff completed its review of the supplemental information determining that the AFC met the listed requirements in all four of the previously deficient technical disciplines, and that the project was data adequate with the filing of the AFC Supplement. At the August 26, 2009 Energy Commission Business meeting the revised AFC was deemed to be data adequate.

PUBLIC WORKSHOPS

On September 16, 2009, an Information Hearing and site visit for HECA was conducted at the Elk Hills Elementary School in the unincorporated community of Tupman. On April 12, 2010, staff conducted a publicly noticed Data Response and Issues Resolution workshop in Tupman and discussed the topics of air quality, cultural resources, biological resources, public health/hazardous materials, hazardous waste, and soil and water resources. Participating agencies in the workshop included the applicant, California Department of Fish and Game, U.S. Fish and Wildlife Services, and intervener.

In addition to this workshop, coordination continues with numerous other local, state and federal agencies that have an interest in the project including the, San Joaquin Valley Air Pollution Control District, California Department of Conservation's Division of Oil, Gas, and Geothermal Resources (DOGGR), California Department of Fish and Game (CDFG), U.S. Department of Energy (DOE), U. S. Environmental Protection Agency (USEPA), and U.S. Fish and Wildlife Service (USFWS).

LIBRARIES

On June 17, 2009, the Energy Commission staff sent the HECA Revised AFC to libraries in the city of Taft, Tehachapi, Boron, Bakersfield, and Buttonwillow. In addition, documents were also sent to state libraries in Eureka, Fresno, Los Angeles, Sacramento, San Diego, and San Francisco.

ENVIRONMENTAL JUSTICE

The steps recommended by the USEPA's guidance documents to assure compliance with the Executive Order 12898 regarding environmental justice are: (1) outreach and involvement; (2) a screening-level analysis to determine the existence of a minority or low-income population; and (3) if warranted, a detailed examination of the distribution of impacts on segments of the population. Though the Federal Executive Order and guidance are not binding on the Energy Commission, staff finds these recommendations helpful for implementing this environmental justice analysis. Staff has followed each of the above steps for the following 7 technical sections in: Air Quality, Noise, Public Health, Socioeconomics, Traffic and Transportation, Transmission Line Safety/Nuisance, and Waste Management (which will be covered in part 2). Over the course of the analysis for each of the 7 areas, staff considered potential impacts and mitigation measures, significance, and whether there would be a disproportionate impact on an environmental justice population.

The purpose of staff's environmental justice screening analysis is to determine whether a low-income and/or minority population exists within the potentially affected area of the proposed site. Staff conducted the screening analysis in accordance with the "Final Guidance for Incorporating Environmental Justice Concerns in USEPA's National Environmental Protection Act Compliance Analysis" (Guidance Document) dated April

1998. People of color populations, as defined by this Guidance Document, are identified where either:

- a low-income and/or minority population of the affected area is greater than 50% of the affected area's general population; or
- the minority population percentage of the area is meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis.

For the HECA project, the total population within a six-mile radius of the proposed site is 1,686 persons, and the total minority population is 893 persons or 52.93% of the total population (see **SOCIOECONOMICS Figure 1**). As the demographic screening area as a whole does exceed 50.0%, as shown in **SOCIOECONOMICS Figure 1,** staff in several technical areas identified in the Executive Summary of this Staff Assessment has considered environmental justice in their environmental impact analyses.

BELOW-POVERTY-LEVEL POPULATION

Staff normally identifies the below-poverty-level population within the six-mile radius using Year 2000 U.S. Census block group data. However, for HECA the poverty data would be inaccurat**e** for the six-mile radius because the census block groups are so large that they include persons well beyond the 6-mile radius and therefore, would misrepresent the poverty data within the six-mile radius (See Socioeconomics for more information).

STAFF'S ASSESSMENT

Each technical section of the PSA contains a discussion of the project setting, impacts, and where appropriate, mitigation measures and proposed conditions of certification. The PSA includes staff's assessment of:

- the environmental setting of the proposal;
- impacts on public health and safety, and measures proposed to mitigate these impacts;
- environmental impacts, and measures proposed to mitigate these impacts;
- the engineering design of the proposed facility, and engineering measures proposed to ensure the project can be constructed and operated safely and reliably;
- project closure;
- project alternatives;
- compliance of the project with all applicable laws, ordinances, regulations and standards (LORS) during construction and operation;
- environmental justice for minority and low income populations;
- proposed conditions of certification; and
- recommendation on project approval or denial.

SUMMARY OF PROJECT RELATED IMPACTS

Staff believes that as currently proposed, including the applicant's and the staff's proposed mitigation measures and the staff's proposed conditions of certification, the project would comply with all applicable laws, ordinances, regulations, and standards (LORS). Staff's preliminary conclusions are that significant adverse direct, indirect or cumulative impacts are not likely to occur in any of the technical areas, although three technical areas (biological resources, cultural resources, and waste management) are currently undetermined with respect to mitigation of potential impact(s), and will be analyzed in Part 2 of the PSA. For a more detailed review of potential impacts, as it pertains to the technical areas that will be discussed in this document (Part 1), see staff's technical analyses in the PSA. The status of each technical area is summarized in the table below.

The discussion following the table identifies the technical areas in the PSA that staff has identified as having outstanding issues which in order to resolve require either additional data, further discussion and analysis or are awaiting conditions from a permitting agency prescribing mitigation. Note: Per the HECA Project Siting Committee's scheduling order, April 22, 2010, the PSA will be analyzed in two parts. Part 1 will consist of the following technical areas: air quality, efficiency, facility design, geology and paleontology, hazardous materials, noise and vibration, public health, reliability, socioeconomic resources, traffic & transportation, transmission line safety nuisance, transmission safety engineering, worker safety and fire protection.

Part 2, expected to be published in late September or early October will include the following technical areas: Biological Resources, Cultural Resources, Soil and Water Resources, Visual Resources, Land Use, Waste Management. Additionally an analysis of the proposed site Alternatives and the Greenhouse Gas Emissions appendix, which will include an analysis of the carbon dioxide enhanced oil recovery and the sequestration proposal (a key component of HECA) will be in Part 2 of the PSA. Staff plans to discuss Part 1 & 2 concurrently with the applicant, interested agencies, and intervenors at a scheduled workshop(s), with date, time and location to be determined.

Technical Area - Part 1	**Complies with LORS**	**Impacts Mitigated**
Air Quality	Yes	Yes*
Efficiency	Not Applicable	Not Applicable
Facility Design	Yes	Yes
Geology & Paleontology	Yes	Yes
Hazardous Materials	Yes	Yes
Noise	Yes	Yes
Public Health	Yes	Yes
Reliability	Not Applicable	Not Applicable
Socioeconomics Resources	Yes	Yes
Traffic & Transportation	Yes	Yes
Transmission Line Safety Nuisance	Yes	Yes
Transmission System Engineering	Yes	Yes

Worker Safety and Fire Protection	Yes	Yes

*Staff finds that mitigation would be provided in the form of emission reduction credits (ERCs) as required by the San Joaquin Valley Air Pollution Control District rules, to fully offset all nonattainment pollutants and their precursors at a minimum ratio of one-to-one, and to reduce the potential impacts of the proposed project to less than significant.

AIR QUALITY

Staff has assessed both the potential for localized impacts and regional impacts for the project's construction and operation, and as a product of this analysis staff has recommended mitigation and monitoring requirements sufficient to reduce the adverse construction and operating emission impacts to less than significant.

The San Joaquin Valley Air Pollution Control District developed an interpollutant trading ratio for sulfur oxides to particulate matter of one-to-one and concluded that this would be protective of managing regional particulate matter impacts and progress towards attainment. However, staff notes that the one-to-one interpollutant trading ratio is lower than what has been historically required by the District on similar past power plant cases, and the methods used by the District in developing the ratio are subject to oversight by the U.S. Environmental Protection Agency, which may affect future power plant cases.

Staff has reviewed the San Joaquin Valley Air Pollution Control District Preliminary Determination of Compliance and finds that it is generally complete and accurate, but notes that there are a number of consistency and continuity issues in the San Joaquin Valley Air Pollution Control District's conditions. Staff has provided a comment letter on the Preliminary Determination of Compliance addressing these issues as has the applicant, and staff believes that there will be a large number of these minor consistency and continuity issue revisions to the San Joaquin Valley Air Pollution Control District conditions that will be presented in the final Determination of Compliance and the Final Staff Assessment.

Global climate change and greenhouse gas emissions from the project will be discussed in a subsequent Staff Assessment submittal (PSA Part 2).

GEOLOGY AND PALEONTOLOGY, AND MINERAL RESOURCES

There are no known viable geologic or mineralogical resources at the site, with the exception of the oil and gas fields of the Naval Petroleum Reserve. Regionally, paleontological resources have been documented within Quaternary alluvium and Tertiary Tulare Formation, similar to deposits that underlie the project site and numerous new fossil localities were discovered during cursory field explorations at the proposed plant site. Potential impacts would be mitigated through worker training and monitoring by qualified paleontologists, as required by Conditions of Certification, **PAL-1** through **PAL-7 (**See Geology and Paleontology, and Mineral Resources for more information).

HAZARDOUS MATERIALS MANAGEMENT

The presence of numerous chemical processes – specifically the larger gasification process and sulfur recovery process that will require large amounts of hazardous materials in closed tanks and piping at elevated temperature and pressure – pose significant risks if not managed properly. Therefore, staff is proposing that the project owner be required to develop a Process Safety Management Plan (PSM Plan), which includes a Hazard and Operability analysis to address several different processes, a Risk Management Plan (RMP) which would include several new Offsite Consequence Analyses, and a Spill Prevention Control and Countermeasures (SPCC) Plan. Staff believes that these plans will identify potential system failures and mitigation to reduce the risk of off-site consequences to the public to less than significant.

In regards to the requirement to conduct a process safety management analysis and prepare a PSM Plan, staff strongly believes that it is imperative that the applicant understands that the entire Cal-OSHA Process Safety Management standard (8 CCR 5189) must be strictly followed and implemented. Towards that, staff believes that when conducting the process hazard analysis required in 8 CCR 5189 (e) (1), the project owner should perform a hazard analysis using at least two different methodologies. One shall be a Hazard and Operability Study (HAZOP) and the other can be chosen from the list in 5189 (e) (1) or one which is recognized by engineering organizations or governmental agencies.

Second, an independent outside third party group of professionals (experienced in the area of hazardous materials management) must provide peer review and approval of the plan before the plan is submitted to the Energy Commission Compliance Project Manager (CPM) for approval. The most important part of the hazard review is described in the California Department of Industrial Relations, Title 8 CCR 5189 (e)(3)(A) which requires that "The process hazard analysis shall be performed by a team with expertise in engineering and process operations, and the team shall include at least one operating employee who has experience and knowledge specific to the process being evaluated. The team shall also include one member knowledgeable in the specific process hazard analysis methodology being used. The final report containing the results of the hazard analysis for each process shall be available in the respective work area for review by any person working in that area". Staff proposes Condition of Certification **Haz-11** which would require two hazard analyses be conducted and that an independent outside third party that also has the required expertise be hired by the project owner to review, evaluate, and sign-off on all process hazard analyses and PSM plans required by Energy Commission conditions (See Hazardous Materials Management for more information).

NOISE

The primary noise sources of HECA include the turbine generators, cooling tower, gasification process equipment, and various pumps, compressors and fans (HEI 2009c, AFC § 5.5.2.3). Other noise sources associated with HECA are related to construction (temporary) and operation (long-term) (See Noise for more information).

PUBLIC HEALTH

In order to properly review the expected – and unexpected emissions from this project, staff spent considerable time evaluating the entire process and even visited a similar gasification facility in Polk County, Florida. As a result of staff's efforts to understand the process and risks involved, staff determined that in order to keep source, fugitive, and accidental emissions to a level that would not present a significant risk to public health, several processes must be managed in greater detail than usual, regardless if the quantities of hazardous materials present are below the federal or state thresholds that would trigger this increased level of management (See Public Health and Safety for more information).

TRAFFIC AND TRANSPORTATION

If the Energy Commission elects to grant certification for this project, staff is proposing six conditions of certification. These conditions of certification are recommended to prevent significant adverse traffic and transportation-related impacts from HECA construction and operation and to ensure that the project would comply with all applicable laws, ordinances, regulations, and standards (LORS) pertaining to traffic and transportation. Energy Commission staff concludes that with implementation of proposed Conditions of Certification **TRANS-1** through **TRANS-9,** the proposed HECA project would not generate a significant impact under the California Environmental Quality Act (CEQA) with respect to Transportation and Traffic (See Traffic and Transportation for more information).

WORKER SAFETY AND FIRE PROTECTION

County Fire Department, in ongoing concurrent siting of other power plant projects (Beacon Solar Power Plant and Ridgecrest Solar Power Plant), both of which are in eastern Kern County, the County has indicated that in general, services provided by the County which include police, fire, and emergency medical services (EMS) services would be impacted by this type of project. Although the Kern County Fire Department has been contacted regarding potential impacts that would be caused by the construction and operation of the HECA project, they have not yet responded. Upon consideration of the County's response to these other projects, staff estimates that direct and cumulative impacts would exist if the proposed HECA project is built. Therefore, Energy Commission Staff recommends mitigation in the form of proposed Condition of Certification **WORKER SAFETY-8** as a place holder until the Kern County Fire Department can specifically identify the necessary mitigation (See Worker Safety and Fire Protection for more information).

ALTERNATIVES SUMMARY

The "Guidelines for Implementation of the California Environmental Quality Act," Title 14, California Code of Regulation, Section 15126.6(a), provides direction by requiring an evaluation of the comparative merits of "a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project." In addition, the analysis must address the "no project" alternative (Cal. Code Regs., tit. 14, §15126.6(e)). A brief discussion of the proposed project's alternative normally appears in this section. Alternatives will be discussed in Part 2 of the PSA.

NOTEWORTHY PUBLIC BENEFITS

Important public benefits discussed under the fiscal and non-fiscal effects are: operation and maintenance, and employment. The annual operations and maintenance budget is expected to be $80 million, including payroll (based on dollars), of which 30% ($19.5 million) of material and supply purchases will occur in Kern County. During the 44-month site preparation, construction, and commissioning/start- up period, the project would provide more than 4,000 jobs.

When completed the HECA facility would permanently employ 100 full-time new employees. It is estimated that 60% of the construction workforce would originate from the Kern County labor force. Los Angeles County would also be a source for construction labor force. It is expected that the labor income and materials spending related to HECA would represent an economic benefit to Kern County. In addition, staff has identified the following significant and environmentally important public benefits:

SOCIOECONOMICS

Important public benefits include both the short-term construction and long-term operational related increases in local expenditures and payrolls, as well as sales tax revenues. Estimated gross public benefits from the HECA project include increases in sales taxes and employment payrolls (See Table 6 in Socioeconomics for summary of economic benefits).

POWER PLANT EFFICIENCY

The project will provide both, baseload and peaking power to help meet the regional electricity demands, by doing so in a fuel-efficient manner, through installing the most modern gas turbine generators available (See Power Plant Efficiency).

RELIABILITY

This project would enhance power supply reliability in the California electricity market by meeting the state’s growing energy demand, contributing to electricity reserves in the region, and providing operating flexibility (that is, the ability to start up, shut down, turn down, and provide load following and spinning reserve) (See Reliability).

RECOMMENDATIONS AND SCHEDULE

For a more detailed review of potential impacts, see staff's technical analyses in the appropriate technical sections contained in the PSA. Staff has listed the outstanding issues as applicable in the technical sections of the PSA. To resolve these issues, staff requires either additional data, further discussion and analysis, or is awaiting information from a permitting agency prescribing mitigation.

INTRODUCTION

Rod Jones

PURPOSE OF THIS REPORT

This Preliminary Staff Assessment (PSA) presents the California Energy Commission (Energy Commission) staff's independent analysis of the Hydrogen Energy California (HECA) Revised Application for Certification (AFC). This PSA is a staff document. It is neither a Committee document, nor a draft decision. The PSA describes the following:

- the proposed project;
- whether the facilities can be constructed and operated safely and reliably in accordance with applicable laws, ordinances, regulations and standards (LORS);
- the environmental consequences of the project including potential public health and safety impacts;
- cumulative analysis of the potential impacts of the project, along with potential impacts from other existing and known planned developments;
- mitigation measures proposed by the applicant, staff, interested agencies and intervenors that may lessen or eliminate potential impacts;
- the proposed conditions under which the project should be constructed and operated, if it is certified; and
- project alternatives.

The analyses contained in this PSA are based upon information from: 1) the Revised AFC; 2) subsequent submittals; 3) responses to data requests; 4) supplementary information from local and state agencies and interested individuals; 5) existing documents and publications; and 6) independent field studies and research. The analyses for most technical areas include discussions of proposed conditions of certification. Each proposed condition of certification is followed by a proposed means of "verification." The verification is not part of the proposed condition, but is the owner's and Energy Commission Compliance Unit's method of ensuring post-certification compliance with adopted conditions of certification.

The Energy Commission staff's analyses were prepared in accordance with Public Resources Code section 25500 et seq. and Title 20, California Code of Regulation section 1701 et seq., and the California Environmental Quality Act (CEQA) (Pub. Resources Code, § 21000 et seq.).

ORGANIZATION OF THE STAFF ASSESSMENT

The PSA Part 1 contains an Executive Summary, Introduction and Project Description. The environmental, engineering, and public health and safety analysis of the proposed project is contained in a discussion of 13 technical areas. Project Alternatives and the remaining six technical areas will be presented in the PSA Part 2.

Each technical area is addressed in a separate chapter. For the environmental assessment they include the following: 1) air quality; 2) hazardous materials management; 3) noise and vibration; 4) public health; 5) socioeconomics: 6) traffic and transportation; 7) transmission line safety and nuisance; and, 8) worker safety/fire protection. For the engineering assessment, technical areas addressed are: 9) power plant efficiency; 10) facility design; 11) geology and paleontology; 12) power plant reliability; and, 13) transmission system engineering. These chapters are followed by a discussion of operation compliance monitoring plans (general conditions), and a list of that assisted in preparing this report.

Each of the 13 technical area assessments includes a discussion of:

- laws, ordinances, regulations and standards (LORS);
- the regional and site-specific setting;
- project specific and cumulative impacts;
- mitigation measures;
- response to agency and public comments (if applicable);
- conclusions and recommendations; and
- conditions of certification for both construction and operation (if applicable).

Pursuant to the Committee Scheduling Order dated April 22, 2010, the Hydrogen Energy California (HECA) will be a two-part document.

Part 2 will include the following technical areas: alternatives, biological resources, cultural resources, soil and water resources, visual resources, land use, waste management; plus an analysis of the proposed site alternatives and the greenhouse gas emissions appendix, which will include an analysis of the carbon dioxide enhanced oil recovery and sequestration proposal (a key component of HECA), to be implemented in coordination with Occidental Petroleum’s Elk Hills Oil Field enhanced oil recovery (EOR) project.

ENERGY COMMISSION SITING PROCESS

The California Energy Commission has the exclusive authority to certify the construction and operation of thermal electric power plants 50 megawatts (MW) or larger. The Energy Commission certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, §25500). The Energy Commission must review power plant AFCs to assess potential environmental and public health and safety impacts, potential measures to mitigate those impacts (Pub. Resources Code, §25519), and compliance with applicable governmental laws and standards (Pub. Resources Code, §25523 (d)).

The Energy Commission’s siting regulations require staff to independently review the Revised AFC and assess whether the list of environmental impacts it contains is complete, and whether additional or more effective mitigation measures are necessary, feasible and available (Cal. Code Regs., tit. 20, §§ 1742 and 1742.5(a)). Staff's independent review is presented in this report (Cal. Code Regs., tit. 20, §1742.5).

In addition, staff must assess the completeness and adequacy of the health and safety standards, and the reliability of power plant operations (Cal. Code Regs., tit. 20, § 1743(b)). Staff is required to coordinate with other agencies to ensure that applicable laws, ordinances, regulations and standards are met (Cal. Code Regs., tit. 20, § 1744(b)).

Staff conducts its environmental analysis in accordance with the requirements of the California Environmental Quality Act. No Environmental Impact Report (EIR) is required because the Energy Commission's site certification program is a certified regulatory program approved by the Resources Agency (Pub. Resources Code, §21080.5 and Cal. Code Regs., tit. 14, §15251 (k)). The Energy Commission is the CEQA lead agency and is subject to all portions of CEQA applicable to certified regulatory activities.

Staff typically prepares a PSA that presents for the applicant, intervenors, agencies, organizations, agencies, other interested parties and members of the public, the staff's analysis, conclusions, and recommendations. Where it is appropriate, the PSA incorporates comments received from agencies, the public and parties to the siting case, and comments made at the workshops.

Staff will provide a comment period to resolve issues between the parties and to narrow the scope of adjudicated issues in the evidentiary hearings. During the period after publishing the PSA, staff will conduct one or more community workshops to discuss its conclusions, proposed mitigation, and proposed compliance-monitoring requirements. Based on the workshops and written comments, staff may refine its analysis, correct errors, and finalize conditions of certification to reflect areas where agreements have been reached with the parties, and publish a Final Staff Assessment (FSA) The FSA will serve as staff's testimony at evidentiary hearings.

The FSA is only one piece of evidence that will be considered by the Committee (two Commissioners who have been assigned to this project) in reaching a decision on whether or not to recommend that the full Energy Commission approve the proposed project. At the public hearings, all parties will be afforded an opportunity to present evidence and to rebut the testimony of other parties, thereby creating a hearing record on which a decision on the project can be based. The hearing before the Committee also allows all parties to argue their positions on disputed matters, if any, and it provides a forum for the Committee to receive comments from the public and other governmental agencies.

Following the hearings, the Committee's recommendation to the full Energy Commission on whether or not to approve the proposed project will be contained in a document entitled the Presiding Members' Proposed Decision (PMPD). Following publication, the PMPD is circulated for 30 days in order to receive public comments. At the conclusion of the comment period, the Committee may prepare a revised PMPD. A revised PMPD will be circulated for a comment period to be determined by the Committee. At the close of the comment period for the revised PMPD, the PMPD is submitted to the full Energy Commission for a decision. Within 30 days of the Energy

Commission decision, any intervenor may request that the Energy Commission reconsider its decision.

AGENCY COORDINATION

As noted previously, the Energy Commission certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, § 25500). However, the Commission typically seeks comments from and works closely with other regulatory agencies that administer LORS that may be applicable to proposed projects. These agencies include the U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, U.S. Army Corps of Engineers, State Water Resources Control Board/Regional Water Quality Control Board, California Department of Fish and Game, the local air quality management district, and the California Air Resources Board.

OUTREACH

LIBRARIES

On June 17, 2009, the Energy Commission staff sent the HECA Revised AFC to libraries in the city of Taft, Tehachapi, Boron, Bakersfield, and Buttonwillow. In addition, documents were also sent to state libraries in Eureka, Fresno, Los Angeles, Sacramento, San Diego, and San Francisco.

PUBLIC ADVISER’S OFFICE INITIAL OUTREACH EFFORTS

The PAO conducts a public outreach effort that is an integral part of the Energy Commission’s AFC review process. The PAO reviewed information provided by the applicant and also conducted its own outreach efforts to identify sensitive receptors (including schools, community, cultural and health facilities, daycare and senior-care centers, as well as environmental and ethnic organizations) within a six-mile radius of the proposed sites for the project. These sensitive receptors, especially elementary schools, are contacted and kept informed of Energy Commission proceedings through PAO outreach. The PAO also works with the siting division and the governmental affairs office to identify and contact local elected and appointed officials from the area.

The PAO provided notification by letter and enclosed notice of the September 16, 2009 Informational Hearing and Site Visit, held at the Elk Hills Elementary School in the unincorporated community of Tupman. Energy Commission regulations require staff to notice, at a minimum, property owners within 1,000 feet of a project and 500 feet of a linear facility such as transmission lines, gas lines and water lines), which was done for HECA. Staff’s ongoing public and agency coordination activities for this project are discussed under the Public and Agency Coordination heading in the Executive Summary section of the PSA.

PROJECT DESCRIPTION

Rod Jones

INTRODUCTION

On July 31, 2008, Hydrogen Energy International, LLC (HEI) submitted an Application for Certification (AFC) to the California Energy Commission to construct and operate Hydrogen Energy California (HECA), an Integrated Gasification Combined Cycle (IGCC) power generating facility proposed for western Kern County, HEI is jointly owned by BP Alternative Energy North America Incorporated and Rio Tinto Hydrogen Energy, LLC. California.

On May 28, 2009, HEI submitted a revised AFC that superseded and replaced the previously filed July 31, 2008 AFC in its entirety. On August 26, 2009, the Energy Commission accepted the revised AFC as complete. The determination initiated Energy Commission staff's analysis of the proposed project. If approved by the Energy Commission, the proposed HECA project would be the first of its kind to be constructed and operated in California. The proposed HECA facility would not be the average fossil fuel facility in that it would generate electricity while increasing California's domestic oil supply.

The proposed HECA facility would gasify petroleum coke (or blends of petroleum coke and coal, as needed) to produce hydrogen to fuel a General Electric (GE) 7FB combustion turbine operating in combined cycle mode. The hydrogen produced by the gasification block would fuel a 390 megawatt (MW) gross/250 MW net combined cycle power plant providing California with baseload power to the grid. The gasification block would also capture approximately 90% of the carbon from the raw syngas (the direct end of the gasification process) at steady-state operation, which would be transported to a custody transfer point within the Elk Hills oil field for CO_2 (carbon dioxide) enhanced oil recovery (EOR) and sequestration.

The proposed project would be located on a 473-acre site (currently used for agricultural production of alfalfa, cotton, and onions), and is comprised of two parcels (Part of Assessor's Parcel # 159-040-16 and 159-040-18, respectively). The project site would be located in western unincorporated Kern County, approximately 1.5 miles northwest of the unincorporated community of Tupman. It is bounded by Adohr Road on the north, Tupman Road to the east, the California State Water Project aqueduct to the south, and Dairy Road to the west. Adohr Road would provide primary access to the site. Most notably - Stockdale highway and Interstate 5 are located approximately one mile to the north and three miles to the east, respectively, and the Elk Hills oil field is located approximately one mile south of the proposed project site (See **Figure 1,** Project Vicinity).

HEI would also purchase 628 acres (four additional parcels) surrounding the project site, referred to as the controlled area in which HEI would be able to control public access and future land uses. Land within the controlled area for the most part would remain in agricultural production.

The nearest single-family residences are 370 feet to the northwest, 1,400 feet to the east, 3,300 feet to the southeast, and 4,000 feet to the north. The proposed project site including the carbon dioxide line and combined potable water/natural gas line are zoned Exclusive Agriculture (A) under the Kern County Zoning Ordinance.

PURPOSE AND OBJECTIVE OF PROJECT

HEI's overall objective is to design, construct and operate an integrated gasification combined-cycle (IGCC) facility that will gasify 100% petroleum coke or blends of petcoke and coal, as needed to produce hydrogen on a commercial scale; capture up to 90% of the carbon produced in this gasification process for low carbon power generation to help meet California's future electrical power needs, and provide CO_2 to the Occidental of Elk Hills, Incorporated's (OEHI) existing enhanced oil recovery operations. As described in the revised AFC, the applicant's key project objectives are as follows:

- to mitigate impacts related to climate change by dramatically reducing average annual greenhouse gas (GHG) emissions relative to the GHG emitted from a conventional power plant by capturing and sequestering carbon dioxide emissions;
- to minimize environmental impacts associated with the construction and operation of the Project through choice of technology, project design and implementation of feasible mitigation measures if necessary;
- to facilitate and support the development of hydrogen infrastructure in California by supplementing the quantities of hydrogen available for future energy and transportation technologies, and
- to conserve domestic energy supplies and enhance energy security by using a by-product from the oil refining process to generate electricity, and enhancing production of domestic petroleum reserves.

If approved by the Energy Commission, HEI would commence construction of HECA in December 2011. The project is expected to take about 44 months for construction, including site preparation. Commissioning and initial startup would occur October 2014 through August 2015, and commercial operation of the proposed project would begin September 2015.

If there are no delays, the construction workforce would average a peak workforce of approximately 1,232 craft workers and 250 contractor staff during month 24 of construction, December 2013. The average workforce during site preparation and construction period would be 740 workers. During operation, HEI estimates that operation and maintenance (O&M) of the project would require 100 skilled full-time employees, including 50 to 60 shift workers (e.g., management and engineers, shift supervision, and shift operating personnel). HECA would be a five-shift operation consisting of 10 people per shift addressing operation related functions.

The total construction cost for the project would be $1.6 billion. Construction costs (total payroll) including cost of equipment, materials and supplies required by the project is estimated to be $1.25 billion. It is expected that the concentration of labor workforce for the project would reside in Kern and Los Angeles counties, which have a sufficient and available construction workforce. With 60 % of the construction workforce originating from the Kern County labor force. An estimated $750 million (60% of non-labor construction cost) would be spent within Kern County on materials and supplies, while the remaining materials, including the project turbines would be purchased outside of Kern County (HECA 2009a, p. 5.8-21)

Construction access would generally be from Interstate 5 to Dairy Road for truck deliveries and via Tupman Road for construction worker vehicles arriving and departing the site. In addition, there would be construction of temporary access roads, worker parking, laydown areas, office and warehouse facilities, installation of erosion control measures and other improvements as needed for construction. Construction worker parking would also occur within the lay down areas (See **Project Description Figure-3**).

HECA would be designed for an operating life of a minimum of 20 years, unless the generation power plant is still economically viable beyond that point. At an appropriate point beyond that, the project would cease operation and close down. At that time, it would be necessary to ensure that the closure occurs in such a way that public health and safety and the environment are protected from adverse impacts. Facility closure would need to be consistent with laws, ordinances, regulations and standards (LORS) in effect at the time of closure. LORS pertaining to facility closure are identified in the technical sections of this assessment.

PROJECT FEATURES

Major on-site project components would include the following:

• Solids handling, gasification, and gas treatment
- Feedstock delivery, handling and storage
- Gasification
- Sour shift/gas cooling
- Mercury removal
- Acid gas removal

• Power Generation
- Combined cycle power generation
- Electrical switching facilities

• Supporting process systems
- Natural gas fuel systems
- Air separation unit (ASU)
- Sulfur recovery unit (SRU)/tail gas treating unit (TGTU)
- Zero liquid discharge (ZLD) units for process and plant waste water streams

- Carbon dioxide compression
- Water treatment plant
- Conventional mechanical-draft cooling towers
- Other plant systems

(HECA 2009a, p.2-5)

Also discussed in this section are other primary project features associated with HECA including construction and laydown areas. All construction and lay down areas of the proposed HECA facility would be located within the 473-acre project site, between five areas: Area 1 (12 acres), Area 2 (36 acres), Area 3 (28 acres); Remote Laydown Area (56 acres) and Air Separation Unit Laydown Area (7.10 acres). See **Project Description Figures 2 & 3** (Project Site – Project Rendering and Preliminary Temporary Construction Facilities Plan including laydown areas). Lands nearest the project site are primarily agricultural and rural residential. The HECA project would be located on land that is under Williamson Act contracts. On June 29, 2010, the applicant received a tentative cancellation of the Williamson Act contracts for the project site by Kern County Board of Supervisors with the caveat that cancellation is subject to payment of a cancellation fee and not to become effective unless the California Energy Commission issues a permit based on environmental review and approval of the project. The cancellation fee that would be paid by the applicant would be applied towards a land bank program, which would allow Kern County to acquire future land for agricultural purposes, if needed. In addition, HECA would have the additional key features described in the following sections.

POWER PLANT EQUIPMENT AND LINEAR FACILITIES ELECTRIC TRANSMISSION

HECA would consist of one General Electric (GE) 7FB combustion turbine-generator (CTG), a steam recovery steam generator (HRSG) and one condensing steam turbine generator. The heat recovery steam generator (HRSG) would be equipped with supplementary firing (duct burner) for use during peak electrical demand. HECA would also use two conventional mechanical-draft cooling towers (21 cells) to support the power block and gasification including the air separation unit. Note: In September 2009, HEI modified the HECA's project description eliminating an auxiliary CTG in order to comply with emissions limits for particulates less than 2.5 microns in diameter ($PM_{2.5}$).

The proposed HECA facility's output would be transmitted to Pacific Gas & Electric's (PG&E) Midway Substation 230-kiovolkt (kV) bus via a 230-kV, single-pole double-circuit X-mile transmission line. The Midway Substation was chosen because of its close proximity to the proposed project site. The California Independent System Operator (CASIO) will be responsible for confirming the feasibility of interconnecting to the Midway Substation when the Phase II Interconnection Study is finalized.

There are two transmission route alternatives (1 and 2) for the proposed project, which are based on the least potential environmental and economic impacts. Options 1 and 2 leave the project site north along Dairy Road, then west on Adohr Road (See **Figure 4 & 5**, Route Alternatives/Site Plan). However, only one of the options will be selected and built.

GASIFICATION BLOCK

The proposed HECA facility would be a nominal 250 MW (net electrical generation output) IGCC power-generating facility consisting of a gasification block/syngas production unit with carbon capture capability and a combined-cycle power block. The gasification block would 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 would 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. This CTG will produce 390 MW gross power output, much of which will be consumed as parasitic load for the facilities' systems, and a net output of 250 MW to the California electrical grid.

The most significant emission source of the HECA would be the CTG/HRSG train. The power block design would be optimized for performance on hydrogen-rich fuel, 100% natural gas, or co-firing hydrogen-rich fuel and natural gas. Most of the hydrogen-rich fuel from the gasification plant would be used to fully load the CTG, with any excess (up to about 10 to 14%) duct fired in the HRSG. The CTG would operate on hydrogen-rich fuel, natural gas, or a mixture of the two (45 to 90% hydrogen-rich fuel) over the emission compliance load range of 60 to 100%. The CTG would be co-fired with natural gas as required to maintain baseload operation whenever the quantity of hydrogen-rich fuel is insufficient… (HEI 2009a, p. 5.1-18).

FEEDSTOCK

Unlike most power plants in California, the proposed HECA facility would use domestic supplies of solid feedstock. The feedstocks for the project include the following sources that are discussed below in more detail:

- Petcoke and western bituminous coal
- Fluxant (crushed aggregate, rock, or sand)
- Natural Gas
- Water
- Oxygen
- Nitrogen

During operation, HECA would rely on petcoke as its primary feedstock. Western bituminous coal (which may be blended to achieve up to 75% thermal input at higher heating value, with petcoke in order to diversify the feedstock) would also be supplied for the project. The bituminous coal would be obtained from a refinery in the Uinta Basin in Utah and Colorado. Futhermore, in order to qualify for federal funding initiatives associated with clean-coal research, minimum coal feedstock requirements may be mandated for limited durations. Feedstock storage would include 15,000 tons of active storage (sufficient for three to 5 days of operation) and at least 30 days inactive emergency storage based on the maximum plant production rate. Active storage would include three 5,000-ton entirely enclosed cone-bottom silos with baghouses[11], with one or more silos dedicated for each type of feedstock. An inactive storage pile, covered with stabilizer, would be provided on site. The truck unloading system, feedstock reclaiming and blending system, and pre-crushing system would have dust collection systems to minimize particulate emissions. The grinding mill feed bins would be totally enclosed and would include baghouses. Petcoke and coal would be transported from the truck unloading system to the active storage silos, pre-crushing system, and grinding mill feed bins in enclosed conveyors with dust collection systems (HECA 2009a, p.2-29).

The petcoke is expected to be the lowest cost feedstock available to HECA, and would likely come from refineries in the Los Angeles, Bakersfield, or northern California areas, and other regional areas. The consumption of the feedstock (petcoke and coal) would be approximately 16,530 tons per day (tpd) and 6.0 million tpd, respectively. The petcoke and coal would be transported to the project site by truck. Coal would be brought in-state by rail and then loaded onto trucks at a nearby transloading terminal.

Gasification is a chemical conversion process that occurs in a reducing environment. Gasification differs from combustion in that gasification produces syngas, an intermediate product that can then be used for other purposes such as generating electricity or producing chemicals. While the term "IGCC" usually implies coal gasification, feedstocks typically include coal (bituminous, sub-bituminous, and lignite), petcoke, biomass, and blends of these materials. HECA would use petcoke and coal/petcoke blends (HECA 2009a, p. 2-23).

PRODUCT OUTPUT

The proposed HECA facility is not a typical power plant. As an IGCC facility HECA would produce several products in addition to electricity. The products that would be created and that form HECA's operational outputs are noted below:

- Carbon dioxide -- Carbon dioxide would be compressed and transported via pipeline to a custody transfer point in the Elk Hills Field for CO_2 EOR and sequestration.
- Molten sulfur -- As a result of operation, the proposed HECA project would produce molten sulfur, which would be sold and transported by truck off site for agricultural and other uses, and
- Gasification solids -- The exact composition of the gasification solids cannot be determined until HECA is operational. But the applicant has stated that the gasification solids are consistent with the proposed feedstock materials.

NATURAL GAS SUPPLY

Natural gas would be delivered to the proposed project either by the PG&E or Southern California Gas Company (SoCal Gas) natural gas pipeline. The utility company selected would construct and own the natural gas line, which would be about 8 miles in length.

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[1] Fabric filters, or baghouses, are widely used for controlling particulate matter from a variety of industrial sources, including utility, industrial, and commercial/institutional coal and wood boilers, metals and mineral processing facilities, and grain milling

The natural gas supply route would extend west along State Route 119, turn north at Tupman Road, and proceed northwest to the proposed project site, and would be in the same trench as the potable water pipeline for a majority of the alignment. The applicant proposes to use horizontal directional drilling to install the pipeline under the Outlet Canal, Kern River, Kern River Flood Control Channel, and California Aqueduct. Please note: The natural gas supply line route may be changed by the applicant and will be analyzed in Part 2 of the PSA and Final Staff Assessment.

Natural gas is required to start up the combustion turbine to the load required to accept hydrogen-rich fuel. Natural gas also serves as a backup fuel to allow electric power generation to continue when hydrogen-rich fuel is not available due to, for example, maintenance of the gasifier unit. Natural gas is also used to fuel the auxiliary boiler, HRSG duct burners, flare pilots, startup of the SRU, and support fuel for the SRU tail gas thermal oxidizer. Natural gas is also used to preheat the gasifier refractory. The natural gas supply meter station will be located within the Controlled Area, southeast of the proposed HECA site (HECA 2009a, p. 2-15*).*

CARBON DIOXIDE (CO_2) SUPPLY

The proposed project would include the construction and operation of a CO_2 pipeline to transfer the CO_2 captured during the gasification process from the proposed project site to a custody transfer point at the Elks Hills Oil Field. The CO_2 pipeline would be owned and operated by the applicant up to the custody transfer facility.

OEHI would be responsible for constructing and owning the pipeline and transfer facilities downstream (4 miles) of the custody transfer point. The CO_2 received by OEHI would be used to facilitate oil production from the Elk Hills reservoir operations through enhanced oil recovery (See CO_2 Enhanced Oil Recovery section for more detail on this aspect of HECA). Two CO_2 pipeline alternative alignments are being considered for the proposed project. Both alignments would extend from the southwestern corner of the proposed project site and are approximately 4 miles in length. In May 2010, CEC staff met with the staff of the United States Fish and Wildlife Services and California Department of Fish and Game to talk about the proposed CO_2 pipeline alignments. Portions of the CO_2 pipeline alignment (as well the potable water/natural gas line) would encroach on an existing conservation easement (Coles Levee Preserve) or lands that have been designated for future conservation for past projects and where a conservation easement (CE) is currently being recorded (e.g., OEHI's habitat conservation plan).

WATER SUPPLY

Brackish ground water would be used for the HECA project supplied by the Buena Vista Water Storage District (BVWSD), a local water district located to the northwest of the proposed project site. The Brackish water supply pipeline would be approximately 15-miles in length and would be used at the project for raw water supply (e.g., cooling tower makeup, evaporative cooling, fire water, gasification, service water, and steam generation).

The proposed average daily water use for HECA would be 4.2 million gallons per day (mgd) on a calendar year basis, and maximum daily use would be 6.2 mgd during hot summer days. Potable water would be supplied through a water supply pipeline approximately 7 miles in length, and be used on site for sanitary and domestic (e.g. drinking) purposes. Please note: The potable water supply pipeline route may be changed by the applicant and will be analyzed in Part 2 of the PSA and Final Staff Assessment. HECA is expected to average 80 persons on site at any given time after construction. The estimated water use would be 1,200 gallons per day (gpd) and 1,800 gpd during peak potable water demand. The average daily water usage during construction would be higher due to compaction, dust control, hydrotesting and sanitary activities. The total average daily water usage would be 10,000 gpd. Hydrotesting in particular is expected to require a maximum daily water usage of 100,000 gallons during the construction period of the project. The potable water would be supplied by the West Kern Water District (WKWD) via the proposed potable water pipeline. WKWD obtains its potable water supply from local groundwater, State Water Project water deliveries and agreements with other Kern County water agencies.

WATER TREATMENT FACILITIES

The project would recycle water and incorporate a zero liquid discharge (ZLD) technology, which would eliminate wastewater discharge. The project would utilize two separate ZLD systems: one for gasification wastewater, and one for mixed plant wastewater.

The primary sources of wastewater at the project treated and recovered in the process mixed plant wastewater ZLD would be from raw water supply treatment and cooling tower blowdown… Cooling tower water that cannot be recycled is sent to a plant ZLD unit where it would be treated and recovered as high purity water and ZLD solids. The ZLD solids would be disposed of at an approved offsite facility in accordance with applicable laws, ordinances, regulations, and standards (LORS).

Also, the gasifier would generate a low volume of process condensate. The process condensate may contain constituents in concentration exceeding Resources Conservation and Recovery Act (RCRA) standards for classification as hazardous waste. Therefore, the low volume of process condensate stream would be treated by a process ZLD, and the produced water would be recycled to the gasifier and the solid waste produced by the process ZLD system would be disposed in accordance with applicable LORS (HECA 2009a, p.5.14-21).

DOMESTIC/SANITARY WASTEWATER

There is no municipal sanitary sewer available nearby to service the project. As a result, the project's sanitary system would consist of a septic collection and forwarding lift station system with a holding tank designed to accommodate the sanitary flow from the buildings that would be located on site (e.g., administration and control building, and restrooms). Sanitary waste generated from HECA's operation would be disposed of in an onsite leach field in accordance with applicable LORS.

STORMWATER RUNOFF

The project would reuse stormwater runoff from the project site where practical. All storm water runoff from the portion of the HECA project site containing industrial activities would be directed to one of two lined storm water retention basins located on the project site. The storm water retention basins would be sized to contain runoff from the Intermediate Storm Design Discharge (ISDD) five-day storm event in accordance with the Kern County Development Standards… In addition, three unlined retention basin would be used to collect stormwater runoff from non-process areas of the site, which would help to further reduce the potential for off-site discharge.

WASTES

Wastes generated by HECA during construction and operation would be typical of an integrated gasification combined-cycle power-generation plant. Solid wastes generated from construction activities may include the following: paper, wood, glass, plastics from packing material, waste lumber, insulation, scrap metal and concrete, and empty non-hazardous containers. These wastes would be considered non-hazardous. Whereas the hazardous wastes generated during construction may include the following: waste paint, spent solvents, waste cleaners, waste oil, oily rags, waste batteries, and spent welding materials. The applicant anticipates recycling or disposing of the hazardous waste via a licensed hazardous waste disposal facility.

During the installation of the electrical transmission line, the natural gas pipeline, the carbon dioxide pipeline, and the process and potable water supply lines, non-hazardous soils and surface demolition debris (such as, concrete, asphalt, and piping) are anticipated, and the wastes would be transported and disposed at an appropriate disposal facility. Any contaminated soils encountered during this phase of the project would be managed in accordance with applicable LORS.

Non-Hazardous solid wastes generated from operation activities such as routine plant maintenance, and office activities may include the following: paper, wood, plastic, metal, cardboard, deactivated equipment, and parts, defective of broken electrical materials, empty non-hazardous containers, and other miscellaneous solid wastes, including the typical refuse generated by workers. The materials would be segregated and recycled, some wastes where appropriate, would be removed on a regular basis by a certified waste-handling contractor for disposal at a Class III landfill.

The gasifier used for HECA would produce a solid slag by-product called gasification solids, which would consist of ash from the petcoke, fluxant, and unconverted carbon that exit the gasifier during the solid phase operation of the project. Gasification solids produced from the use of feedstock that is at least 50% coal is excluded from hazardous waste regulations and requirements, per the exclusions in applicable in federal and California regulations (i.e., Title 40 of Code of Federal Regulations (40 CFR) Section 261.4 (b)(7)(ii)(F), and California regulation 22 CCR Section 66261.4(b)(5)(A)).

Reuse potential of gasification solids is being evaluated by the applicant and includes possibilities in the cement industry, aggregate or road base industry, metal reclaiming for vanadium and nickel), and/or blending with petcoke to form a sellable fuel, and gasification solids that are produced from feedstocks of less than 50% would be analyzed characterized, and managed in accordance with applicable LORS (HECA 2009a, p. 5-13-12).

COMBUSTION TURBINE GENERATOR

The applicant eliminated the auxiliary combustion turbine generator (CTG) General Electric (GE) LMS 100 and reduced the rates for particulate matter less than 10 microns in diameter (PM10) and particulate matter less than 2.5 microns diameter (PM2.5) from the GE Frame 7B CTG and the heat recovery steam generator when firing hydrogen-rich fuel. The modification is not expected to result in any substantial changes to the schedule, costs, workforce, or traffic during construction or operations, or equipment use during construction of the proposed project (URS 2009f, p. 2-1).

ZERO LIQUID DISCHARGE

The HECA would use a zero liquid discharge (ZLD) technology to treat wastewater generated from the raw water supply treatment and cooling tower blowdown and gasifier; therefore there would be no wastewater discharge.

OCCIDENTAL PETROLEUM'S ENHANCED OIL RECOVERY PROJECT

Occidental Petroleum Company of Elk Hills, Inc. (OEHI) would be the recipient of the CO_2 generated by the proposed HECA facility, which would be used to extend the life of OEHI's existing enhanced oil recovery program in an area within the Elk Hills Unit. Part 2 of the PSA will include an analysis of the carbon dioxide enhanced oil recovery and sequestration proposal (including indirect effects).

REFERENCES

HECA 2009a - Hydrogen Energy International, LLC /J. Briggs (tn 51735). Revised Application for Certification, dated 05/28/09. Submitted to CEC/Docket Unit on 05/28/09.

U.S. Environmental Protection Agency – Environmental Technology Verification Program; Baghouse Filtration Products [online] http://www.epa.gov/etv/pubs/600f06019.pdf

URS 2009f - URS/D. Shileikis (tn 53498). Amendment to the Revised Application for Certification, dated 09/30/09. Submitted to CEC/Docket Unit on 09/30/09.

PROJECT DESCRIPTION - FIGURE 1

Hydrogen Energy California - Project Vicinity

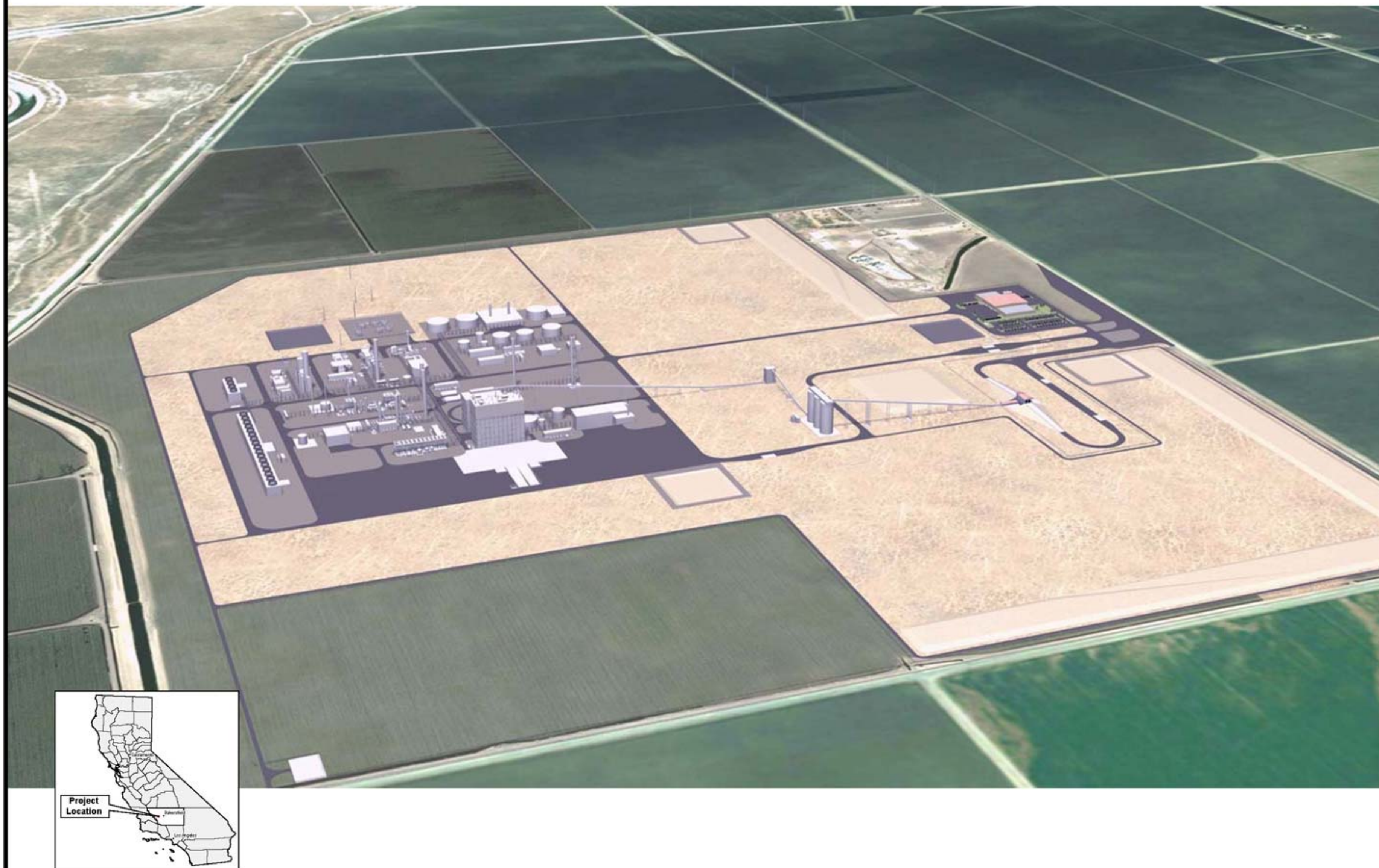
PROJECT DESCRIPTION

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Revised AFC, May 2009, Figure 1-1

PROJECT DESCRIPTION - FIGURE 2

Hydrogen Energy California - Project Site - Project Rendering

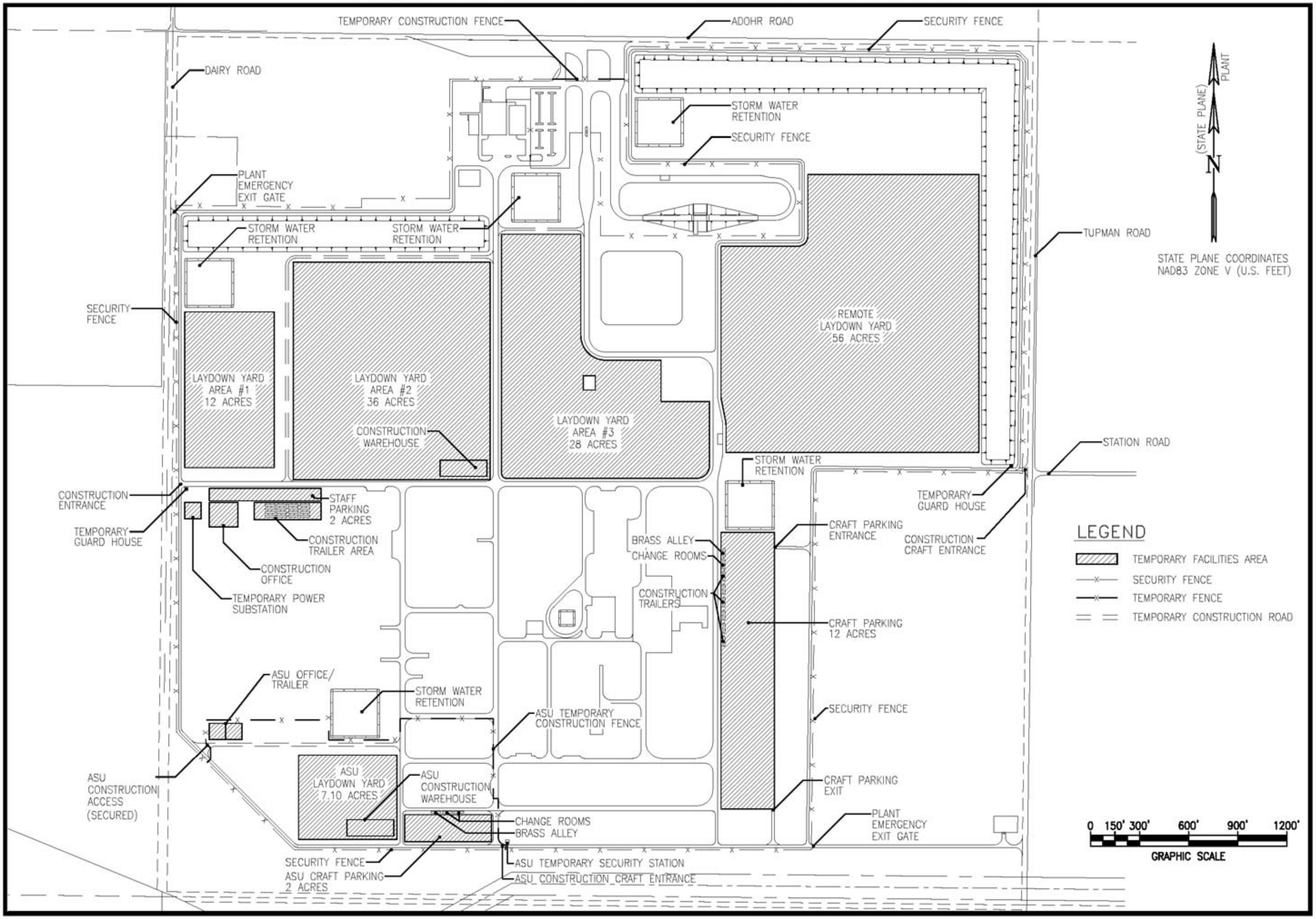


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Revised AFC, May 2009, Figure 1-4

PROJECT DESCRIPTION - FIGURE 3

Hydrogen Energy California - Preliminary Temporary Construction Facilities

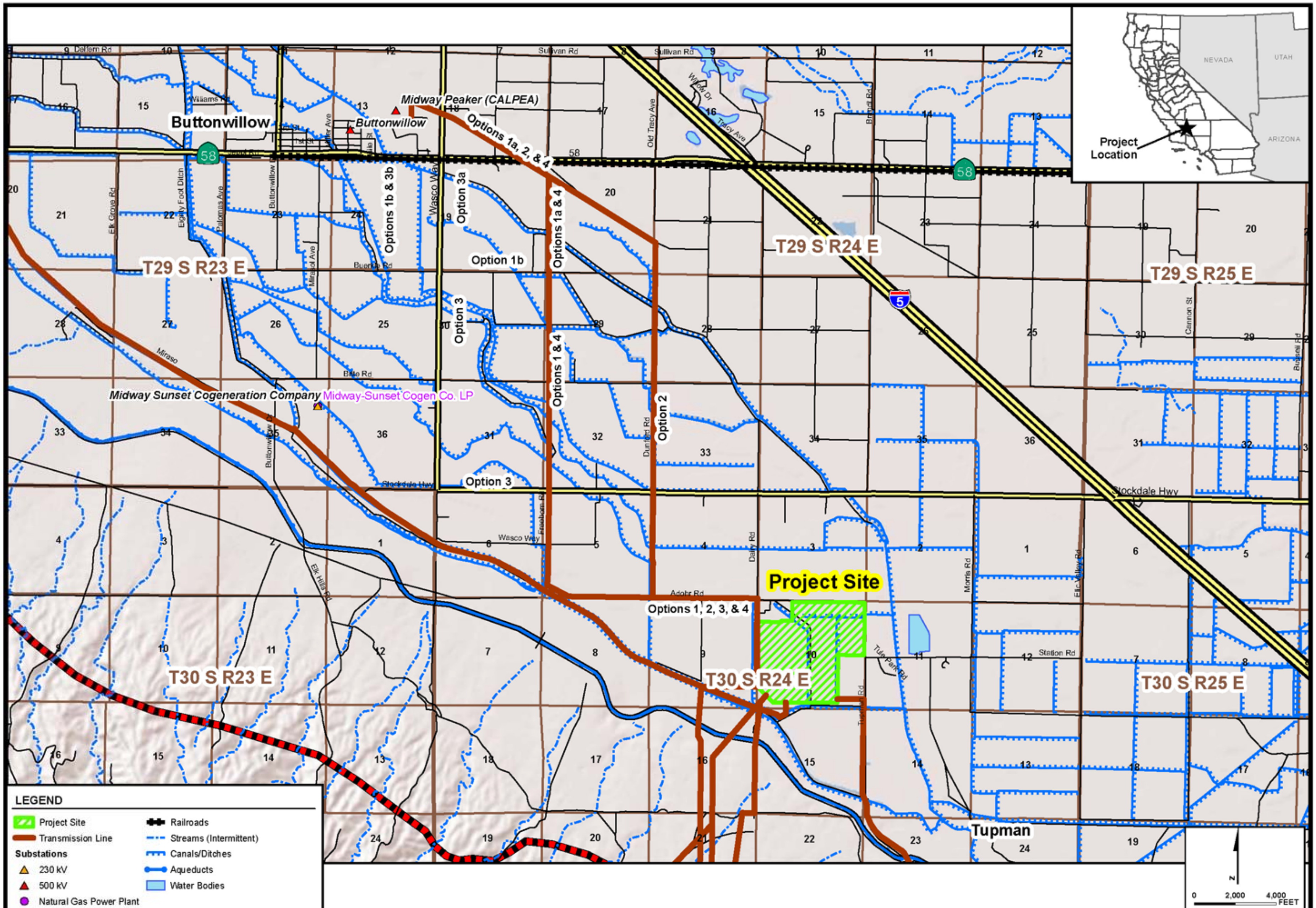


PROJECT DESCRIPTION

SOURCE: Revised AFC, May 2009, Figure 2-40

PROJECT DESCRIPTION - FIGURE 4

Hydrogen Energy California - Route Alternatives

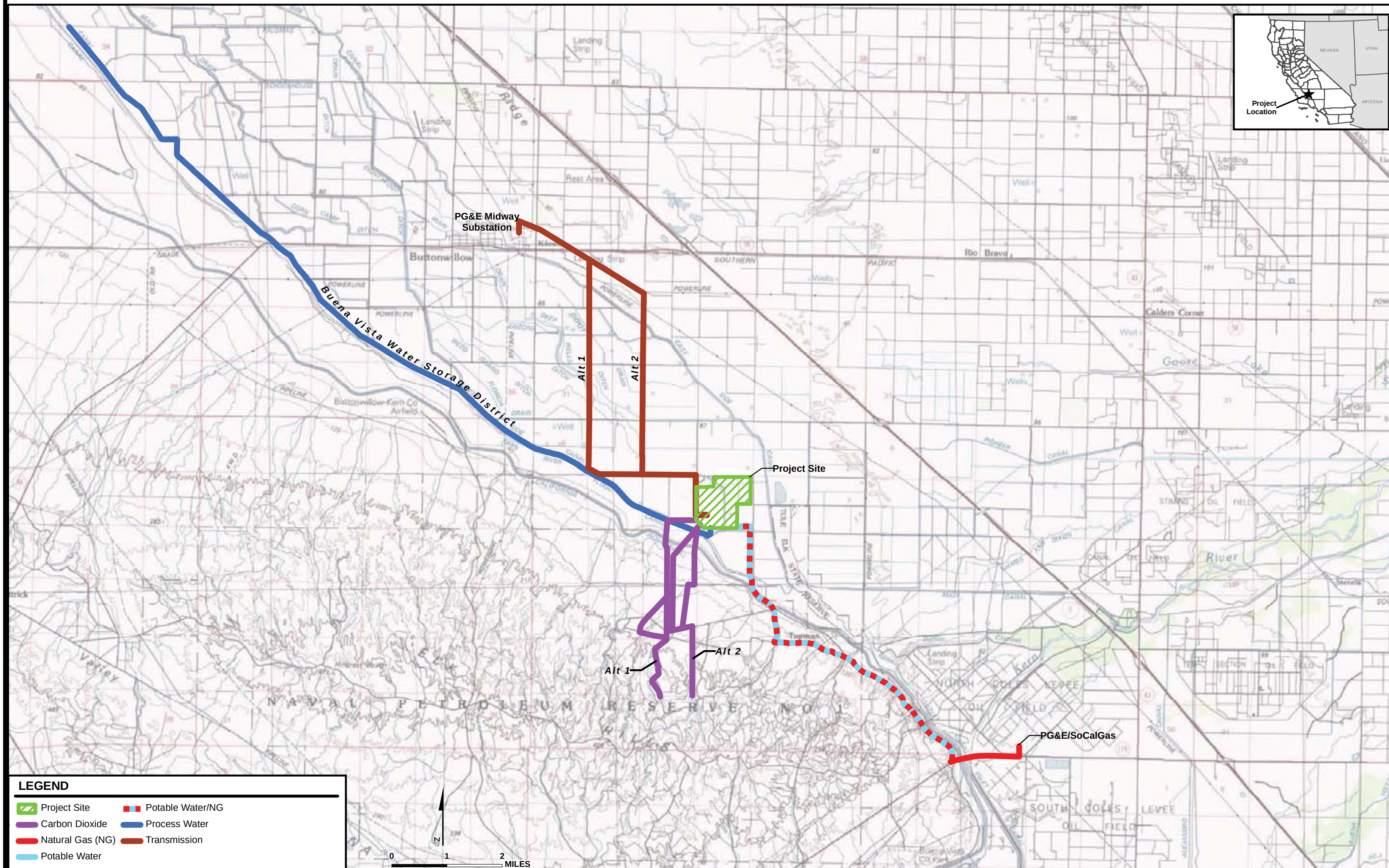


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Revised AFC, May 2009, Figure 4-1

PROJECT DESCRIPTION - FIGURE 5

Hydrogen Energy California - Site Plan

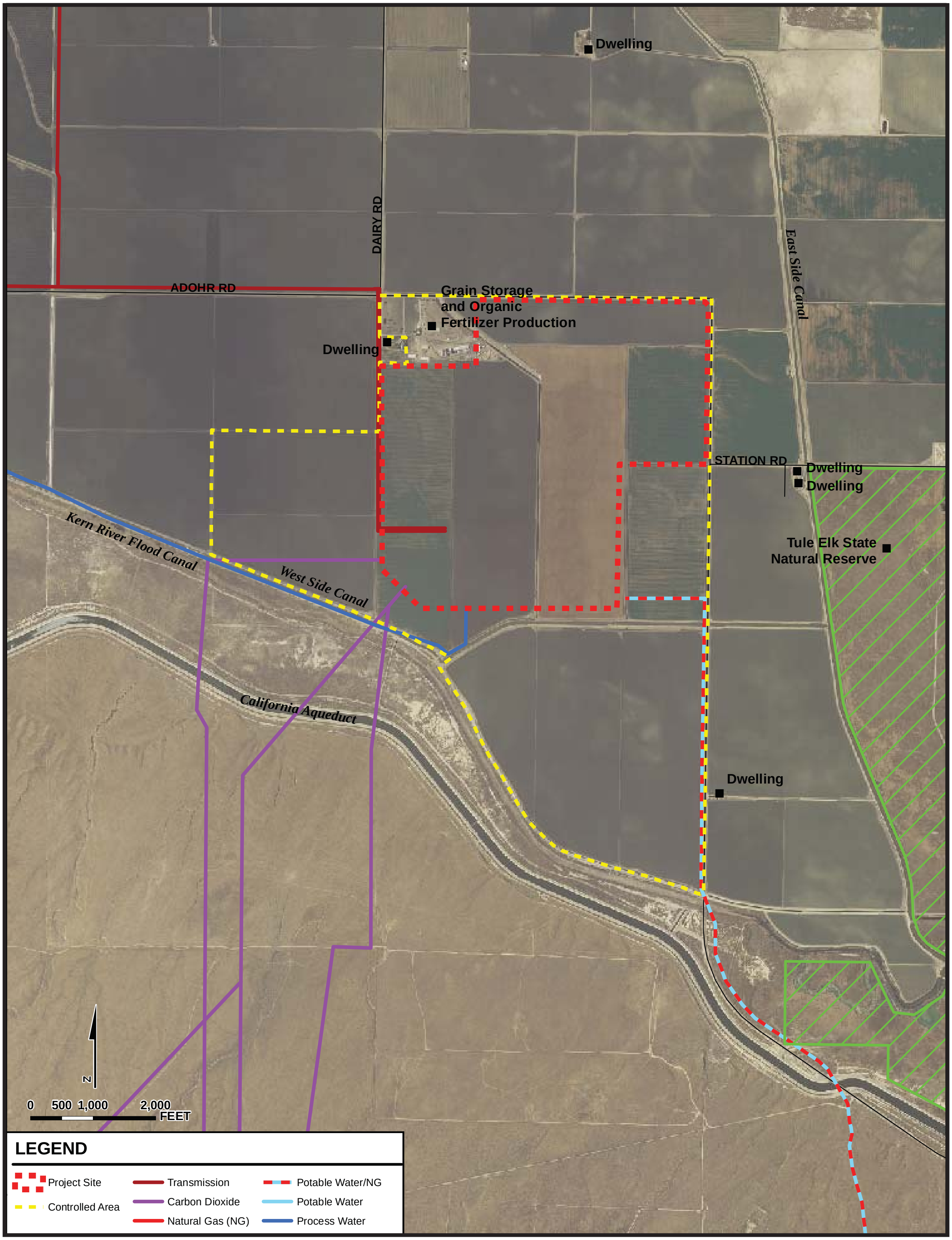


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Revised AFC, May 2009, Figure 2-7

PROJECT DESCRIPTION - FIGURE 6

Hydrogen Energy California - Overview - Existing Land Uses



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Revised AFC, May 2009, Figure 5.4-2

ENVIRONMENTAL ASSESSMENT

AIR QUALITY

William Walters, P.E.

SUMMARY OF CONCLUSIONS

The Hydrogen Energy California Project should comply with all applicable Laws, Ordinances, Regulations, and Standards and should not result in significant air quality impacts provided the recommended conditions of certification are adopted by the Commission and implemented by the project owner. The project has secured emission reduction credits in sufficient quantity to meet San Joaquin Valley Air Pollution Control District requirements. Additionally, these emission reduction credits would fully offset all onsite and offsite project emissions of nonattainment pollutants and their precursors that occur within the San Joaquin Valley Air Basin at a minimum offset ratio of 1:1.

Staff has assessed both the potential for localized impacts and regional impacts for the project's construction and operation, and as a product of this analysis staff has recommended mitigation and monitoring requirements sufficient to reduce the potential adverse construction and operating emission impacts to less than significant.

The San Joaquin Valley Air Pollution Control District developed an interpollutant trading ratio for sulfur oxides to particulate matter of one-to-one and concluded that this would be protective of managing regional particulate matter impacts and progress towards attainment. However, staff notes that the one-to-one interpollutant trading ratio is lower than what has been historically required by the District on similar past power plant cases, and the methods used by the District in developing the ratio are subject to oversight by the U.S. Environmental Protection Agency, which may affect future power plant cases.

Staff has reviewed the San Joaquin Valley Air Pollution Control District Preliminary Determination of Compliance and finds that it is generally complete and accurate, but notes that there are a number of consistency and continuity issues in the San Joaquin Valley Air Pollution Control District's conditions. Staff has provided a comment letter on the Preliminary Determination of Compliance addressing these issues as has the applicant, and staff believes that there will be a large number of these minor consistency and continuity issue revisions to the San Joaquin Valley Air Pollution Control District conditions that will be presented in the final Determination of Compliance and the Final Staff Assessment.

Global climate change and greenhouse gas emissions from the project will be discussed in part 2 of this staff assessment.

INTRODUCTION

Hydrogen Energy International, LLC (applicant) submitted an Application for Certification (AFC) to construct and operate an integrated gasification combined cycle (IGCC) power generating facility near the community of Tupman in Kern County, California. The proposed project would use both petroleum coke, a product from California refineries that is currently both used in existing California power plants and shipped overseas, and coal, from mines located outside of the State of California, as feedstocks to generate the hydrogen-rich fuel that will be the primary fuel for a combined cycle gas turbine. The project includes the use of coal due to requirements of the U.S. Department of Energy. The HECA project would be a 390 MW gross, 250 MW net baseload electrical power facility that would occupy 473 acres of what is currently farmland located in an agricultural area of the county, 2.5 miles northwest of the unincorporated community of Tupman.

This analysis evaluates the expected air quality impacts from the emissions of criteria air pollutants from both the construction and operation of the HECA Project. Criteria air pollutants are defined as air contaminants for which the state and/or federal governments, per the California Clean Air Act and federal Clean Air Act, have established ambient air quality standards to protect public health.

The criteria pollutants analyzed within this section are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), and particulate matter (PM). Lead is not analyzed as a criteria pollutant, but lead and other toxic air pollutant emissions impacts are analyzed in the Public Health Section of this document. Two subsets of particulate matter are inhalable particulate matter (less than 10 microns in diameter, or PM10) and fine particulate matter (less than 2.5 microns in diameter, or PM2.5). Nitrogen oxides (NOx, consisting primarily of nitric oxide [NO] and NO_2) and volatile organic compound (VOC) emissions readily react in the atmosphere as precursors to ozone and, to a lesser extent, particulate matter. Sulfur oxides (SOx) readily react in the atmosphere to form particulate matter and are major contributors to acid rain; the terms nitrogen oxides (NOx) and sulfur oxides (SOx) are also used when discussing these two pollutants.

In carrying out the analysis, the California Energy Commission (Energy Commission) staff evaluated the following three major issues:

- Whether HECA is likely to conform with applicable Federal, State and San Joaquin Valley Air Pollution Control District (SJVAPCD or district) air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- Whether HECA is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards (Title 20, California Code of Regulations, section 1742 (b)); and
- Whether the mitigation proposed for HECA is adequate to lessen the potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The federal, state, and local laws and policies applicable to the control of criteria pollutant emissions and mitigation of air quality impacts for the HECA project are summarized in **Air Quality Table 1.**Staff's analysis examines the project's compliance with these requirements.

Air Quality Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	**U.S. Environmental Protection Agency**
40 CFR 50	National Ambient Air Quality Standards (NAAQS).
40 CFR 51	New Source Review (NSR) – Requires NSR permit for new stationary sources. This requirement is addressed through SJVAPCD Rule 2201, with the exception of PM2.5 NSR (100 ton/year trigger), that is not currently included in SJVAPCD Rule 2201.
40 CFR 52.21	Prevention of Significant Deterioration (PSD) – Requires dispersion modeling to demonstrate no violation of NAAQS or PSD increments, for pollutants that attain the NAAQS.
40 CFR 60, Subpart Db	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60 - New Source Performance Standards (NSPS)]. Requires monitoring, notification, and reporting of emissions and operation of the proposed natural gas fired auxiliary boiler.
40 CFR 60, Subpart Y	Standards of Performance for Coal Preparation and Processing Plants. Requires dust collector particulate matter source testing, visual emissions testing and visual monitoring of equipment, and recordkeeping for the coal handling, storage, and emission control equipment.
40 CFR 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines. Replaces Subparts Da and Subpart GG for the proposed combustion turbines and duct burners with heat recovery steam generators. Requires the proposed combined cycle units to achieve 15 ppm NOx and achieve fuel sulfur standards.
40 CFR 60, Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Requires the proposed emergency engines to achieve specific emission standards depending on the size and model year of the engine.
40 CFR 70, CAA Sec 401, 42 USC 7661	Federal Title V Operating Permit Program. Consolidates the federally-enforceable operating limits. Application required within one year following start of operation. This program is within the jurisdiction of the SJVAPCD with U.S. EPA oversight [SJVAPCD Rule 2520].
40 CFR 72, CAA Sec 401 42 USC 7651	Title IV Acid Rain – Applicable to electrical generating units greater than 25 MW. Requires Title IV permit and compliance with acid rain provisions, implemented through the Title V program. This program is within the jurisdiction of the SJVAPCD with U.S. EPA oversight [SJVAPCD Rule 2540].
40 CFR Part 93 General Conformity	Requires determination of conformity with State Implementation Plan for Projects requiring federal approvals if project annual emissions are above specified levels.

State	**California Air Resources Board and Energy Commission**
Health and Safety Code (HSC) Section 44300-44384; Title 17 of The California Code of Regulations (17 CCR 93300-93300.5) Toxic “Hot Spots” Acts	Requires preparation and biennial updating of facility emission inventory of hazardous substances; health risk assessments.
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with approved clean air plan. The SJVAPCD New Source Review (NSR) program is consistent with regional air quality management plans.
California Health & Safety Code Section	Public Nuisance Provisions. Outlaws the discharge of air contaminants that cause nuisance, injury, detriment, or annoyance.

41700	
California Public Resources Code 25523(a); 20 CCR 1752, 2300, 2309 and DIV. 2, Chap. 5, Art. 1, Appendix B, Park (k)	Requires that CEC's decision on the AFC includes requirements to assure protection of environmental quality; AFC is required to address air quality protection.
California Code of Regulations (CCR) 17 CCR § 93115	Airborne Toxics Control Measure for Stationary Compression Ignition Engines. Limits the types of fuels allowed, establishes maximum emission rates, establishes recordkeeping requirements on stationary compression ignition engines, including emergency generator and fire water pump engines.
California Code of Regulations (CCR) 13 CCR § 2485	Airborne Toxics Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. Generally prohibits idling longer than five minutes for diesel-fueled commercial motor vehicles.

Local	**San Joaquin Valley Air Pollution Control District**
Regulation I, General Provisions	Establishes the requirements and standards for stack monitoring (Rule 1080), source sampling (Rule 1081), and breakdown events (Rule 1100) and identifies penalties.
Regulation II, Permits	Establishes the regulatory framework for permitting new and modified sources. Included in these requirements are the federally-delegated requirements for NSR, the Title V Operating Permit Program, and the Title IV Acid Rain Program.
Rule 2201, New and Modified Stationary Sources	Establishes the pre-construction review requirements for new, modified or relocated emission sources, in conformance with NSR to ensure that these facilities do not interfere with progress in attainment of the ambient air quality standards and that future economic growth in the San Joaquin Valley is not unnecessarily restricted. Establishes the requirement to prepare a Preliminary Determination of Compliance (PDOC) and Final Determination of Compliance (FDOC) during District review of an application for a power plant. This regulation establishes Best Available Control Technology (BACT) and emission offset requirements.
Rule 2520, Federally Mandated Operating Permits	Establishes the permit application and compliance requirements for the federal Title V federal permit program. HECA qualifies as a Title V facility and must submit the Title V application within twelve months after starting operation.
Rule 2540, Acid Rain Program	Implements the federal Title IV Acid Rain Program, which requires subject facilities to obtain emission allowances for SOx emissions and requires fuel sampling and/or continuous monitoring to determine SOx and NOx emissions.
Rule 4001, New Source Performance Standards	Specifies that a project must meet the requirements of the Federal New Source Performance Standards (NSPS), according to Title 40, Code of Federal Regulations, Part 60. The specific NSPS subparts that are applicable to the HECA project include: • Subpart Db - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units • Subpart Y - Standards of Performance for Coal Preparation and Processing Plants • Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines • Subpart KKKK - Standards of Performance for Stationary Combustion Turbines
Rule 4002, National Emission Standards for HAPs	Incorporated the National Emission Standards for Hazardous Air Pollutants (HAPs) from Part 61 and Part 63, Chapter I, Subpart C, Title 40 CFR and applies to major sources of HAPs, and Subpart ZZZZ applies to the emergency engines.

Rule 4101, Visible Emissions	Prohibits visible air emissions, other than water vapor, of more than No. 1 on the Ringelmann chart (20 percent opacity) for more than three minutes in any one-hour.
Rule 4102, Nuisance	Prohibits any emissions which cause injury, detriment, or public nuisance.
Rule 4201-4202, Particulate Matter	Limits particulate emissions from any source that emits or may emit dust, fumes, or total suspended particulate matter.
Rule 4301, Fuel Burning Equipment	Limits the concentrations of combustion contaminants and specified emission rates from any fuel burning equipment.
Rule 4311, Flares	Limits NOx, VOC, and SOx from the operation of flares.
Rule 4320, Boilers, Steam Generators, and Process Heaters	Limits NOx, CO, SO_2, and PM10 from boilers, steam generators, and process heaters.
Rule 4702, Internal Combustion Engines	Limits emissions of NOx, CO, and VOC from internal combustion engines. However, as emergency units, the proposed emergency engine-generator set and emergency fire water pump engine are exempt from emission limits, subject to monitoring and recordkeeping.
Rule 4703, Stationary Gas Turbines	Limits the proposed stationary gas turbine emissions of NOx to 3 ppmv and CO to 25 ppmv over a 3-hour averaging period. Provided certain demonstrations are made, the emission limits do not apply during startup, shutdown, or reduced load periods (defined as “transitional operation periods”).
Rule 4801, Sulfur Compounds	Limits SOx emissions greater than 0.2 percent by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes.
Rule 7012, Hexavalent Chromium	Limits emissions of hexavalent chromium from circulating water in cooling towers.
Regulation VIII, Fugitive PM10 Prohibition	Sets forth the requirements and performance standards for the control of emissions from fugitive dust causing activities.

SETTING

METEOROLOGICAL CONDITIONS

The climate in California is typically dominated by the eastern Pacific high-pressure system centered off the coast of California. In the summer, this system results in low inversion layers and clear skies inland and typically early morning fog by the coast. In winter, this system promotes wind and rainstorms originating in the Gulf of Alaska and striking Northern California.

The climate of the southern San Joaquin Valley is characterized by hot dry summers and mild winters with precipitation almost exclusively in the winter. Very little precipitation occurs during the summer months because the Pacific high-pressure blocks migrating storm systems. Beginning in the fall and continuing through the winter, the storm belt and zone of strong westerly winds begins to greatly influence California. Temperature, winds, and rainfall are variable during fall and winter months, and stagnant conditions occur more frequently than during summer.

Wind speeds are generally higher in summer than in winter and are typically north-northwesterly winds. During the spring, summer, and fall, the stronger winds are caused by a combination of offshore and thermal low pressure resulting from high temperatures in the Central Valley. During the winter months, winds are more variable and are predominantly northerly. Calm conditions occur more during winter, but are relatively infrequent throughout the year. Valley fog often occurs during these calm, stagnant atmospheric conditions, when temperature inversions trap a layer of cool, moist air near the surface. The annual rainfall in the Tupman area is less than 7 inches and precipitation mostly occurs, over 90 percent, during October through April. Summers have average daily high temperatures between 95 and 96°F for the two hottest months (July and August). During December and January, average daily low temperatures are between 33 and 36°F (WC 2010).

Along with the wind flow, atmospheric stability and mixing heights are important factors in the determination of pollutant dispersion. Atmospheric stability is an indicator of the air turbulence and mixing. During the daylight hours of the summer when the earth is heated and air rises, there is more turbulence, more mixing, and thus less stability. During these conditions there is more air pollutant dispersion and therefore usually reduced air quality impacts near any single air pollution source. During the winter months between storms, however, very stable atmospheric conditions occur, resulting in very little mixing. Under these conditions, minimal air pollutant dispersion occurs, and consequently higher air quality impacts may result near sources. Because lower mixing heights generally occur during the winter, along with lower mean wind speeds and less vertical mixing, dispersion occurs less rapidly.

SENSITIVE RECEPTORS

The general population includes many sensitive subgroups that may be at greater risk from exposure to emitted pollutants. These sensitive subgroups include the very young, the elderly, and those with existing illnesses. In addition, the location of the population in the area surrounding a project site may have a large bearing on health risk. The nearest sensitive receptor (Elk Hills Elementary School) is located approximately 2.5 miles southeast of the project site in Tupman. There are a few farm residences that surround the site location. The nearest resident is located adjacent to the northwest portion of the project site, which is approximately one-third of a mile south of the IGCC main complex. Only two other residences and the Tule Elk Preserve State Park are within one mile of the IGCC main complex on the project site.

EXISTING AMBIENT AIR QUALITY

The Federal Clean Air Act and the California Clean Air Act both require the establishment of standards for ambient concentrations of air pollutants, called ambient air quality standards (AAQS). The state AAQS, established by the California Air Resources Board, are typically lower (more protective) than the federal AAQS, which are established by the United States Environmental Protection Agency (U.S. EPA). The state and federal air quality standards are listed in **Air Quality Table 2**. The averaging times for the various air quality standards, the times over which they are measured, range from one-hour to an annual average. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant in a cubic meter of air (mg/m^3 or μg/m^3, respectively).

Air Quality Table 2
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.075 ppm [a] (147 μg/m^3)	0.070 ppm (137 μg/m^3)
	1 Hour	--	0.09 ppm (180 μg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9.0 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide [b] (NO_2)	Annual	0.053 ppm (100 μg/m^3)	0.03 ppm (57 μg/m^3)
	1 Hour	0.100 ppm	0.18 ppm (339 μg/m^3)
Sulfur Dioxide [c] (SO_2)	24 Hour	--	0.04 ppm (105 μg/m^3)
	3 Hour	0.5 ppm (1,300 μg/m^3)	--
	1 Hour	0.075 ppm	0.25 ppm (655 μg/m^3)
Particulate Matter (PM10)	Annual	--	20 μg/m^3
	24 Hour	150 μg/m^3	50 μg/m^3
Fine Particulate Matter (PM2.5)	Annual	15 μg/m^3	12 μg/m^3
	24 Hour	35 μg/m^3	--
Sulfates (SO_4)	24 Hour	--	25 μg/m^3
Lead	30 Day Average	--	1.5 μg/m^3
	Calendar Quarter	1.5 μg/m^3	--
Hydrogen Sulfide (H_2S)	1 Hour	--	0.03 ppm (42 μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	--	0.01 ppm (26 μg/m^3)
Visibility Reducing Particulates	8 Hour	--	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.

Source: ARB 2010a.
Notes:
[a] The 2008 standard is shown above, but as of September 16, 2009 this standard is being reconsidered. The 1997 8-hour standard is 0.08 ppm.
[b] The U.S. EPA is in the process of implementing their new 1-hour NO_2 standard, which became effective April 12, 2010. This standard is based on the 3-year average of the 98th percentile of the yearly distribution of 1-hour daily maximum concentrations.
[c] The U.S. EPA has recently adopted a primary 1-hour SO_2 standard which will become effective on August 23rd, 2010, and revoked the primary 24-hour and annual SO_2 standards. This new 1-hour standard is based on the 3-year average of the 99th percentile of the yearly distribution of 1-hour daily maximum concentrations.

In general, an area is designated as attainment if the concentration of a particular air contaminant does not exceed the standard. Likewise, an area is designated as nonattainment for an air contaminant if that contaminant standard is violated. In circumstances where there is not enough ambient data available to support designation as either attainment or nonattainment, the area can be designated as unclassified. The unclassified area is normally treated the same as an attainment area for regulatory purposes. An area could be attainment for one air contaminant while nonattainment for another, or attainment for the federal standard and nonattainment for the state standard for the same air contaminant.

The project site is located in western Kern County within the San Joaquin Valley Air Basin (SJVAB) and is under the jurisdiction of the San Joaquin Valley Air Pollution Control District. The Western Kern County in the SJVAB is designated as nonattainment for the federal and state ozone standards, the state PM10 standard, and the federal and state PM2.5 standards. This area is designated as attainment or unclassified for the state and federal CO, NOx, SOx, and federal PM10 standards. **Air Quality Table 3** summarizes the area's attainment status for various applicable state and federal standards. The ambient air quality standards that staff uses as a basis for determining project significance are health-based standards. They are set at levels to adequately protect the health of all members of the public, including those most sensitive to adverse air quality such as the aged, people with existing illnesses, and infants and children, while providing a margin of safety.

Air Quality Table 3
Federal and State Attainment Status for the San Joaquin Valley

Pollutant	Attainment Status	
	Federal	**State**
Ozone – 1 hour	No Federal Standard[b]	Nonattainment/Severe
Ozone – 8 hour	Nonattainment/Extreme	Nonattainment
CO	Attainment[a]	Attainment
NO_2	Attainment[a,d]	Attainment
SO_2	Attainment[e]	Attainment
PM10	Attainment[c]	Nonattainment
PM2.5	Nonattainment	Nonattainment

Source: SJVAPCD 2010b, U.S. EPA 2010a
[a] Unclassified/Attainment – The attainment status for the subject pollutant is classified as either attainment or unclassified.
[b] Effective June 15, 2005, the U.S. EPA revoked in the federal 1-hour ozone standard, including associated designations and classifications. However, U.S. EPA had previously classified the SJVAB as extreme nonattainment for this standard and redesignated the SJVAB as extreme nonattainment effective June 4, 2010.
[c] On September 25, 2008, U.S. EPA redesignated the San Joaquin Valley to attainment for the PM10 National Ambient Air Quality Standard (NAAQS) and approved the PM10 maintenance Plan.
[d] - Nitrogen dioxide attainment status for the new federal 1-hour NO_2 standard is scheduled to be determined by January 2012.
[e] – Sulfur dioxide attainment status for the new federal 1-hour SO_2 standard is scheduled to be determined by June 2012.

The proposed project site is an undeveloped area in western Kern County, approximately 2.5 miles northwest of the unincorporated community of Tupman and approximately 7.0 miles west of the border of the city of Bakersfield.

The monitoring station located closest to the proposed project site is the Shafter-Walker Street Station, which is approximately 13 miles northeast of the project site. This station monitors ozone, NO_2, and VOCs. The next closest monitoring stations are the Bakerfield-5558 California Avenue and the Bakersfield Golden Highway stations, located approximately 18 miles and 21 miles east of the project site. These two stations monitor all pollutants, except SO_2. The latest SO_2 data from these stations are dated year 2001, and the Fresno First Street monitoring station, located approximately 100 miles to the north northwest, is the only ambient pollutant monitoring station within the SJVAB which currently measures SO_2.

Air Quality Table 4 summarizes the historical air quality data for the project location, recorded at Shafter-Walker Street station for ozone (2004-2009) and NO_2 (2004-2009), Bakersfield-5558 California Avenue for PM10 (2004-2009), PM2.5 (2004-2009), and CO (2004-2005). CO concentrations for the years 2006-2009 were recorded at Bakersfield-Golden State Highway monitoring station. SO_2 data are collected from the Fresno-1st Street station for 2007-2009. In **Air Quality Figure 1**, the short term normalized concentrations are provided from 1998 to 2009. Normalized concentrations represent the ratio of the highest measured concentrations in a given year to the most-stringent applicable national or state ambient air quality standard. Therefore, normalized concentrations lower than one indicates that the measured concentrations were lower than the most-stringent ambient air quality standard.

Ozone

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between directly emitted nitrogen oxides (NOx) and hydrocarbons (Volatile Organic Compounds [VOC]) in the presence of sunlight to form ozone.

Air Quality Table 4 and **Air Quality Figure 1** clearly shows that ozone concentrations measures near the project site continue to violate the applicable standards. The peak 1-hour and 8-hour ozone concentration typically occur between May and September when ambient conditions are most favorable for the ozone photochemical reactions.

Nitrogen Dioxide

The entire air basin is classified as attainment for the state 1-hour and annual and federal annual NO_2 standards. The nitrogen dioxide attainment standard could change due to the new federal 1-hour standard, although a review of the air basin–wide monitoring data suggest this would not occur for the SJVAB.

Approximately 90 percent of the NOx emitted from combustion sources is nitric oxide (NO), while the balance is NO_2. NO is oxidized in the atmosphere to NO_2, but some level of photochemical activity is needed for this conversion. The highest concentrations of NO_2 typically occur during the fall. The winter atmospheric conditions can trap emissions near the ground level, but lacking significant photochemical activity (sun light), NO_2 levels are relatively low. In the summer the conversion rates of NO to NO_2 are high, but the relatively high temperatures and windy conditions disperse pollutants, preventing the accumulation of NO_2. The NO_2 concentrations in the project area are well below the state and federal ambient air quality standards.

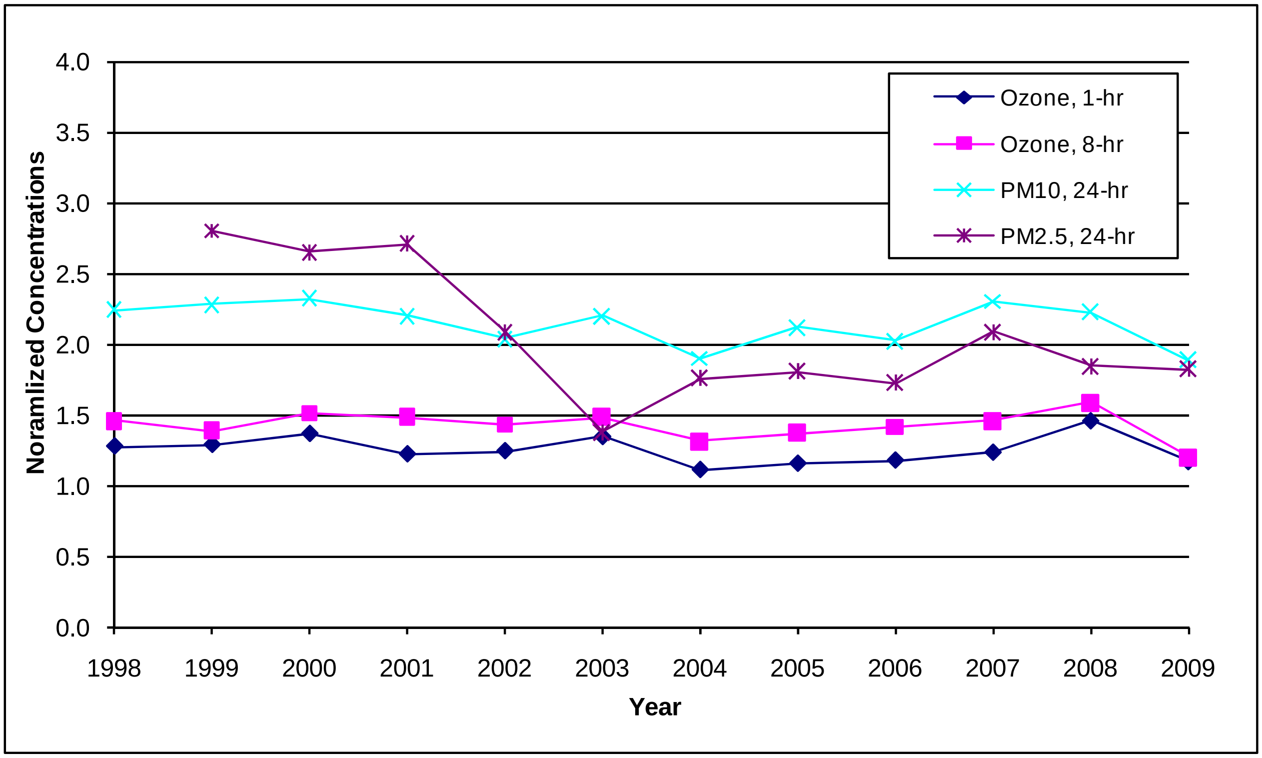
Air Quality Table 4
Criteria Pollutant Summary
Maximum Ambient Concentrations (ppm or μg/m^3)[1]

Pollutant	Averaging Period	Units	2004	2005	2006	2007	2008	2009	Limiting AAQS
Ozone	1 hour	ppm	0.100	0.104	0.106	0.111	0.131	0.105	0.09
Ozone	8 hours	ppm	0.092	0.096	0.099	0.102	0.111	0.084	0.07
PM10 [a]	24 hours	μg/m^3	95.0	106.0	101.0	115.0	111.3	94.5	50
PM10 [a]	Annual	μg/m^3	43.1	40.4	48.5	48.5	55.4	41.2	20
PM2.5 [a, b]	24 hours	μg/m^3	61.5	63.2	60.5	73.0	64.5	69.2	35
PM2.5 [a, c]	Annual	μg/m^3	18.9	22.4	21.6	22.0	21.9	21.2	12
CO	1 hour	ppm	3.1	3.1	3.3	2.8	3.5	2.2	20
CO	8 hours	ppm	1.83	2.20	2.19	1.97	2.17	1.49	9.0
NO_2	1 hour (State)	ppm	0.074	0.063	0.100	0.101	0.057	0.052	0.18
NO_2	1 hour (Fed)[d]	ppm	---	0.055	0.073	0.065	0.052	---	0.10
NO_2	Annual	ppm	0.017	0.015	0.019	0.014	0.014	0.012	0.03
SO_2	1 hour (State)	ppm	---	---	---	0.024	0.012	0.009	0.25
SO_2	1 hour (Fed)[e]	ppm	---	---	---	0.008	0.006	0.008	0.075
SO_2	24 hours	ppm	---	---	---	0.007	0.003	0.005	0.04

Source: ARB 2010b, ARB 2010c, U.S. EPA 2010b
Notes:
[a] Exceptional PM concentration events, such as those caused by wind storms are not shown where obvious; however, some exceptions events may still be included in the data presented.
[b] 24-hour PM2.5 data shown are the 98th percentile concentrations.
[c] Annual average PM2.5 data shown are National annual average for those years when state annual average data are not available.
[d] 1-hour federal NO_2 data are 98th percentile of daily 1-hour maximums.
[e] 1-hour federal SO_2 data are 99th percentile of daily 1-hour maximums.

[1] Staff is currently obtaining information from the District regarding appropriate ambient background, including corrections to the available data, so the data presented in this table and **Air Quality Table 5** may be updated in the Final Staff Assessment (FSA).

Air Quality Figure 1
Normalized Maximum Short-Term Historical Air Pollutant Concentrations



Source: ARB 2010b, ARB 2010c, U.S. EPA 2010b

A Normalized Concentration is the ratio of the highest measured concentration to the applicable most stringent air quality standard. For example, in 1999 the highest one-hour average ozone concentration measured at the Shafter Walker Street station was 0.116 ppm. Since the most stringent ambient air quality standard is the state standard of 0.09 ppm, the 1999 normalized concentration is 0.116/0.09 = 1.289.
*used Shafter Walker Street monitoring station data (1998-2009) for all ozone, and Bakersfield-5558 California Avenue monitoring station (1998-2009) for PM10 and PM2.5.

Carbon Monoxide

The project site area within the SJVAB is classified as attainment for the state 1-hour and 8-hour CO standards. The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground. The project area has a lack of significant mobile source emissions and based on Bakersfield monitoring stations, data is locally expected to have CO concentrations that are well below the state and federal ambient air quality standards.

Particulate Matter (PM10) and Fine Particulate Matter (PM2.5)

PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere.

The area is nonattainment of the State PM10 standards, attainment of the federal PM10 standards, and nonattainment of the State and Federal PM2.5 standards. **Air Quality Figure 1** shows recent PM10/2.5 concentrations. The figure shows fluctuating concentrations patterns, and shows clear exceedance of the State PM10 and State PM2.5 standards. It should be noted that exceedance does not necessarily mean violation or nonattainment, as exceptional events such as those caused by high winds or large wildfires may be determined to not be violations.

Fine particulate matter, or PM2.5, is derived mainly from either the combustion of materials, or from precursor gases (SOx, NOx, and VOC) through complex reactions in the atmosphere. PM2.5 consists mostly of sulfates, nitrates, ammonium, elemental carbon, and a small portion of other organic and inorganic compounds.

Sulfur Dioxide

The SJVAB is classified as attainment for the state and federal SO_2 standards. The sulfur dioxide attainment status could change due to the new federal 1-hour standard; although a review of the air basin's monitoring data suggest this would not occur for the SJVAB.

Sulfur dioxide is typically emitted as a result of the combustion of fuel containing sulfur; such as coal, oil, and to a much less extent natural gas and motor vehicle fuels. This project uses a high sulfur content fuel feedstock but the gasification process separates most of this into elemental sulfur, which greatly reduces the SO_2 pollution potential from this project's emission sources.

Summary

In summary, staff recommends the background ambient air concentrations in **Air Quality Table 5** for use in the modeling and impacts analysis. The maximum criteria pollutant concentrations from the past three years of available data collected at the monitoring stations near the proposed project site, excluding exceptional events, are used to determine the recommended background values.

Air Quality Table 5
Staff Recommended Background Concentrations (µg/m^3)

Pollutant	Averaging Time	Recommended Background	Limiting Standard	Percent of Standard
NO_2	1 hour CAAQS	190.2	339	56%
	1-hour NAAQS	119.5	188	63%
	Annual	26.6	57	47%
PM10	24 hour	115.0	50	230%
	Annual	55.4	20	277%
PM2.5	24 hour	73.0	35	209%
	Annual	22.0	12	183%
CO	1 hour	4,025	23,000	18%
	8 hour	2,411	10,000	24%
SO_2	1 hour CAAQS	62.9	655	10%
	1-hour NAAQS	18.3	197	9%
	3 hour	56.6	1,300	4%
	24 hour	18.4	105	18%

Source: ARB 2010b, ARB 2010c, U.S. EPA 2010b and Energy Commission Staff Analysis
Note: PM2.5 24-hour data shown in **Air Quality Table 4** are the 98th percentile values, 1-hour NAAQS NO_2 data are 98th percentile of maximum daily values, and 1-hour NAAQS SO_2 are 99th percentile of maximum daily values.

Where possible, staff prefers that the recommended background concentrations come from nearby monitoring stations with similar characteristics. For this project the Shafter-Walker Street monitoring station, providing the ozone and NO_2 background concentrations, is the closest monitoring station to the project site. The Bakersfield-5558 California Avenue station and the Bakersfield-Golden State Highway monitoring station are the next closest stations which provide the PM10, PM2.5 and CO background concentration data. The Fresno-1st Street monitoring station provides the background SO_2 concentration data.

The background concentrations for PM10 and PM2.5 are above the most restrictive existing ambient air quality standards, while the background concentrations for the other pollutants are all well below the most restrictive existing ambient air quality standards.

The pollutant modeling analysis was limited to the pollutants listed above in **Air Quality Table 5**; therefore, recommended background concentrations were not determined for the other criteria pollutants (ozone, lead, visibility, etc.).

PROJECT DESCRIPTION AND EMISSIONS

Hydrogen Energy International LLC (HEI), jointly owned by BP Alternative Energy North America Inc., and Rio Tinto Hydrogen Energy LLC, has proposed to build an Integrated Gasification Combined Cycle (IGCC) power generating facility called Hydrogen Energy California (HECA or the “project”) in Kern County, California. The facility would gasify petroleum coke (petcoke), or blends of petcoke and coal, ranging from 100 percent petcoke to 75 percent coal/25 percent petcoke blend, as needed[2], to produce a hydrogen-rich synthetic fuel gas (syngas)[3] to fuel a combustion turbine operating in combined cycle mode. The facility would be located on the 473 acres of project site near an oil and gas producing area in Kern County, California.

The project is designed to produce 250 MW net electrical generation of low-carbon base load power to the grid. The gasification process would capture approximately 90 percent of the carbon dioxide from the shifted[4] syngas to be used for Enhanced Oil Recovery (EOR) and sequestration (storage) in the Elk Hills Oil Field Unit, owned by Occidental Petroleum. The gasification process is complex and includes many separate process units that are summarized in the operations emissions section.

HEI would own and operate the IGCC facilities and carbon dioxide (CO_2) pipe line, entering a long-term lease for the Kern County Project Site. The transmission line would

[2] During the Department of Energy demonstration period the facility will be operating on a minimum of 75 percent coal (energy input basis) and after which the facility operations will be limited as noted above.

[3] Hydrogen-rich fuel is primarily composed of hydrogen (~89.4 percent), and also includes carbon dioxide (~5.8 percent), nitrogen (~2.5 percent), carbon monoxide (~1.3 percent), argon (~1 percent), and other trace gases.

[4] The gasification process initially creates an unshifted syngas that is composed primarily of carbon monoxide, carbon dioxide, and hydrogen. For this project the syngas is then shifted using the water-gas reaction to shift the carbon monoxide to hydrogen creating the shifted syngas. The shifted syngas then undergoes further processing/cleaning to remove the carbon dioxide and other impurities to create the hydrogen-rich fuel that is ready for use in the gas turbine.

also be owned by HEI up to the point of interconnect (Midway Substation) as stipulated by the California Independent System Operator (CAISO). Natural gas and water supply lines would be owned by others. Ownership of the carbon dioxide would reside with HEI until the HECA facility fence line when ownership would shift to Occidental Petroleum.

Staff provided a number of data requests regarding the construction and operations emission estimates and air dispersion modeling analysis (CEC 2009o), which the applicant responded to in a number of separate data response documents[5] by providing additional project description, revised emissions estimates, and revised dispersion modeling analysis. Staff has compiled the latest information from the AFC (HEI 2009c), the project modifications (HEI 2009f) and the air quality data responses in this Preliminary Staff Assessment (PSA) section. Staff has reviewed the revised emission estimates and air dispersion modeling analysis[6] and finds them to be reasonable considering the level of emissions mitigation now stipulated to by the applicant.

CONSTRUCTION

On-site construction activities of the Hydrogen Energy California project would include the following; 1) clearing and grubbing of sparse vegetation; 2) grading; 3) hauling and payout of equipment; 4) materials and supplies; 5) Project construction and testing. The project would also include the following off site facilities; 1) electrical transmission line; 2) natural gas supply; 3) water supply pipelines; 4) carbon dioxide pipeline. The construction/commissioning period is expected to last approximately 44 months (37 months of construction with 10 months of partially overlapping initial commissioning), beginning in December, 2011.

Emissions of fugitive particulate matter can result from disturbed areas due to grading, excavating, and construction of project structures. Different areas within the project site would be disturbed at different times during the 37 month construction period. Additionally, paved and unpaved road travel would create fugitive dust emissions.

Combustion emissions during the construction of the project result from exhaust sources, including diesel construction equipment used for site preparation and building/structure construction, water trucks used to control dust emissions, diesel-powered welding machines, electric generators, air compressors, water pumps, diesel trucks used for deliveries, and automobiles and trucks used by workers to commute to and from the construction site.

The short-term maximum emissions would occur during the 21st month of the construction schedule. Activities in the 21st month include excavating, material handling, and extensive building construction. The maximum annual emissions were based on the

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[5] This includes the following AFC and data response references: HEI 2009c, HEI 2009f, L&W 2010h, L&W 2010L, URS 2009b, URS 2009c, URS 2009g, URS 2009j, URS 2009k, URS 2010a, URS 2010k, and URS 2010L. The majority of the most recent and updated information for air quality emissions and impacts is contained in URS 2010L and the San Joaquin Valley Air Pollution Control District's Preliminary Determination of Compliance (SJVAPCD 2010c).

[6] This includes a review of the emission source inputs, including the type of source (point, volume, area) and the variables used to describe each source (emissions, height, location, temperature, etc. as appropriate).

worst 12 consecutive months of the construction period, which are months 17 through 28 of construction. Applicant estimates for the highest emissions during construction are provided in **Air Quality Table 6** and **Air Quality Table 7**.

Air Quality Table 6
Maximum Daily Construction Emissions

Activity (lbs/day)	NOx	CO	VOC	SOx	PM10	PM2.5
Onsite Combustion	12,146	5,421	1,639	11.81	658.16	604.08
Onsite Fugitive	--	---	----	---	32.36	6.16
Subtotal Onsite Emissions	12,146	5,421	1,639	11.81	677.64	610.79
Offsite Combustion	1,639	1,333	361.65	2.39	123.06	112.52
Offsite Fugitive	--	---	----	---	364.22	61.55
Subtotal Offsite Emissions	1,639	1,333	361.65	2.39	487.28	174.07
Total Max. Daily Emissions	13,785	6,754	2,001	14.2	1,177.8	784.3

Source: HEI 2009c
Notes:
a. Worst-case daily emissions would occur during Month 21 of construction.

Air Quality Table 7
Maximum Annual Construction Emissions

Activity (ton/year)	NOx	CO	VOC	SOx	PM10	PM2.5
Onsite Combustion	39.77	21.94	5.85	0.05	2.27	2.04
Onsite Fugitive	--	---	----	---	1.46	0.25
Subtotal Onsite Emissions	39.77	21.94	5.85	0.05	3.73	2.29
Offsite Combustion	8.45	53.81	4.97	0.10	1.04	0.96
Offsite Fugitive	--	---	----	---	48.08	8.13
Subtotal Offsite Emissions	8.45	53.81	4.97	0.10	49.12	9.09
Total Max. Daily Emissions	48.22	75.75	10.82	0.15	52.85	11.37

Source: HEI 2009c
Notes:
a. Worst-case annual emissions were determined 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 consecutive period (i.e., months 17 to 28).

INITIAL COMMISSIONING

The initial commissioning of a power plant refers to the time between the completion of construction and the reliable production of electricity for sale on the market. For most power plants, normal operating emission limits usually do not apply during the initial commissioning activities due to the need to test individual components during commissioning, often before emission controls are operational.

The commissioning and initial startup is currently scheduled to require 12 months to complete. The commissioning for the project would require four distinct phases which are described as follows.

1. Commissioning utility and support systems

2. Power block commissioning on natural gas

3. Gasification block commissioning

4. Power block commissioning on hydrogen-rich fuel

Commercial operation would start when the commissioning and startup activities are completed and the licensor/contractor guarantees and milestones have been achieved.

The commissioning activities would occur in several phases. They would begin with the utility and support systems, which includes electric power, water treating, natural gas supply, auxiliary boiler, cooling tower, and safety systems. This commissioning phase would be completed in about a month.

After the first commissioning phase, power block would be commissioned before commissioning of gasification block to ensure the reliability of the power block to supply substantial amounts of electrical power to be consumed by the gasification block. The power block would be commissioned on natural gas only during this period. This phase would last approximately 3 months, followed by gasification block commissioning.

Gasification block commissioning would occur for a total of 6 months, following the process flow path. The gasification, rectisol, and sulfur recovery unit (SRU) flares would be tested with natural gas and nitrogen. The tail gas thermal oxidizer would also be commissioned on natural gas. Included in the gasification block initial commission emissions are the balance of plant (BOP) operations not otherwise included in the CTG/HRSG initial commissioning emission estimate.

The last commissioning phase is to commission power block on hydrogen-rich fuel. The hydrogen-rich fuel and nitrogen blending systems would be commissioned, and the CTG combustors would be tuned for different fuel types. The CTG would be performance-tested on hydrogen-rich fuel at the end of this commissioning phase.

Emissions estimates for each commissioning phase are shown in **Air Quality Table 8**.

Air Quality Table 8
Summary of Commissioning Emissions

Phase	Duration	NOx	CO	VOC	SOx	PM10
Max Hourly Commissioning Emissions (lb/hr)						
CTG/HRSG on Natural Gas	1 hr	345.0	2,200.0	345.0	4.7	18.0
CTG/HRSG on Hydrogen-Rich Fuel	1 hr	167.0	394.0	98.0	3.1	36.0
Total Commissioning Emissions (tons)[a]						
Utility and Support Systems	1 month	0.24	0.51	0.05	0.02	0.05
CTG/HRSG on Natural Gas	3 months	65.78	51.75	5.08	1.48	7.97
Gasification Block and BOP	6 months	69.15	456.09	2.89	28.88	3.77
CTG/HRSG on Hydrogen-Rich Fuel	2 months	17.22	13.26	2.83	0.83	9.93
Total Commissioning Emissions	**12 months**	**152.39**	**521.61**	**10.85**	**31.21**	**21.72**

Source: HEI 2009c, URS 2009c, and URS 2009j as integrated and interpreted by staff
Note: a – The commissioning schedule is shown to be sequential through these four commissioning phases, the maximum hourly emissions are not provided by the applicant for the utility and support systems or gasification block commissioning, and the CTG/HRSG commissioning does not include the main power block cooling tower emissions but the Air Separation Unit (ASU) and Gasification power block cooling tower use appears to be overestimated in a manner that should compensate or overcompensate for the lack of power block cooling tower operation in this emission estimate.

OPERATIONAL PHASE

Equipment Description

The IGCC power generating facility consists of a power block, a gasification block/syngas production block, and auxiliary equipment. For emission calculation purposes, the emission sources are separated into these units as follows;

Power Block	• Combustion Turbine (GE 7FB) • Power Block Cooling Tower
Gasification Block	• Gasifier Refractory Heaters • Auxiliary Boiler • Gasification Flare • Sulfur Recovery Unit (SRU) Flare • Rectisol Flare • Tail Gas Thermal Oxidizer • Air Separation Unit (ASU) Cooling Tower • Gasification Cooling Tower • Carbon Dioxide Vent • Dust Collection (Feedstock)
Auxiliary Equipment	• Diesel Generator • Emergency Diesel Firewater Pump

Power Block

Power Block CTG/HRSG Unit

The project would operate as a baseload low-carbon power generation facility primarily using hydrogen-rich fuel[7] generated from the project's gasification unit. The gasification unit would have two normally operating GE quench gasifiers and one spare gasifier. This configuration would maximize the availability of hydrogen-rich fuel sufficient to allow baseload operation of the GE Frame 7FB combustion turbine generator (CTG). If enough gasifier feedstock is available, surplus hydrogen-rich fuel may be available for duct firing in the HRSG. Depending on the amount of hydrogen-rich fuel, the GE Frame 7 FB CTG may be fired with 100% hydrogen-rich fuel, with 100% natural gas, or a mixture of two. If the CTG is co-fired, the co-firing range would be from 45 percent hydrogen-rich fuel to 90 percent hydrogen-rich fuel over the CTG load range of 60 to 100 percent. Regardless of the fuel type, the CTG/HRSG would always be started up using natural gas only and then transition to hydrogen-rich fuel use. The maximum expected operating schedule for the CTG/HRSG is provided in **Air Quality Table 9**.

[7] A nitrogen diluent, from the ASU, is used with the hydrogen-rich fuel to reduce combustion temperatures in the gas turbine combustor in order to reduce thermal NOx creation.

Air Quality Table 9
Maximum Annual CTG/HRSG Operating Schedule

Operating Conditions	Annual Duration (hr)
Total Hours of Operation	8,322
Total Hours of Cold Start	30 (3 hrs x 10 Cold Starts)
Total Hours of Hot Start	20 (1 hr x 20 Hot Starts)
Total Hours of Shutdown	15 (0.5 hr x 30 Shutdowns)
Hours of Duct Burner Operation	8,257

Source: URS 2010L

For permitting purposes the duct burner operation has been assumed to operate 100 percent of the time the turbine is operating, excepting startup and shutdown periods. The applicant assumes that early operation (first three years) would require up to 30 percent natural gas use (heat input basis) and that mature operation would require 10 percent natural gas use.

The GE Frame 7 FB uses diffusion combustors with steam injection to control NOx formation. Post-combustion NOx from the HRSG stack would be reduced using the selective catalytic reduction (SCR) system. Aqueous ammonia is injected into the stack gases upstream of a catalytic system that converts nitrogen oxide and ammonia to nitrogen and water. An oxidation catalyst would be used to control emissions of CO and VOC.

Power Block Cooling Tower

Power cycle heat rejection would consist of a steam surface condenser, cooling tower, and cooling water system. Approximately 175,000 gpm of water would be circulated in the power block cooling tower, and the power block cooling tower would operate 8,322 hours annually. The cooling tower would operate with a maximum total dissolved solids (TDS) concentration of 9,000 ppmw[8] and the cooling tower's particulate emissions would be controlled with a high efficiency mist eliminator.

Gasification Block

Gasifier

Two gasifiers would be operated in normal operation, and one spare gasifier would be available. Each gasifier would have one natural gas-fired burner which would be used during startup to warm the gasifier's refractory. These three burners would operate at 18 MMBtu per hour, and the total annual operation would be 3,600 hours. The gasifiers work by first creating an unshifted syngas (primarily composed of CO, CO_2, and hydrogen) that is shifted through the water-gas shift reaction to convert the CO to hydrogen and CO_2, which is then processed further to remove the CO_2 and impurities to create the hydrogen-rich fuel[9].

[8] The TDS levels could range from 3,000 to 9,000 ppmw for the project's cooling towers, depending on the raw water quality and operating cycles of concentration for each cooling tower. For permitting purposes the maximum level of 9,000 ppmw has been assumed.

[9] This explanation is an oversimplification as the process may be sour (high sulfur) or sweet, and there are other steps, such as mercury removal, before the hydrogen-rich gas is ready to be used as a fuel in the gas turbine.

The gasifier unit also has fugitive emissions from the piping components from various VOC and CO laden streams, including methanol, propylene, H_2S-laden methanol, and the CO_2-laden methanol streams.

Auxiliary Boiler

The auxiliary boiler, fired exclusively on natural gas, would be used to provide steam to facilitate CTG startup. The boiler, with a maximum heat input of 142 MMBtu/hour, would be operated up to 2,190 hours annually. The boiler would have an ultra-low NOx burner and flue gas recirculation (FGR) NOx emissions control.

Gasification Flare

The gasification flare would be used to safely dispose of gasifier startup gases, syngas (also called unshifted and shifted gases[10]), and hydrogen-rich fuel generated during short-term combustion turbine outages and other unplanned power plant upsets or equipment failures[11]. Reduced pressure sour gas would be scrubbed to remove sulfur and both high and low pressure gases would be vented through knockout drums to remove water and other entrained liquids.

Sulfur Recovery Unit (SRU) Flare

The SRU flare would be operated to safely dispose of acid-gas streams containing sulfur from the acid gas removal (AGR) unit, gasification unit, and sour water stripper unit during startup or during emergency or upset events. The acid gas is first vented through an emergency caustic scrubber and knockout drum to remove sulfur compounds and entrained liquids and then vented to the flare for oxidation of the remaining acid gas.

Rectisol Flare

The rectisol flare would be used as an emergency flare to safely dispose of low temperature gas streams from the AGR unit and its associated refrigeration unit during startup, shutdown, and unplanned upsets or emergency events. These gases, which are first vented through a knockout drum to remove any entrained liquids prior to introduction to the flare header, are below the freezing point of water and require segregation from the other flared gases.

SRU/Tail Gas Thermal Oxidizer

This unit recovers sulfur from the processing facility through the use of a Claus unit. A separate Tail Gas Treatment Unit (TGTU) processes the tail gas from the SRU, recycling part back to the Claus unit and the remaining overhead gas, which is

[10] Shifted gas sent to the flare would contain large amounts of hydrogen and carbon dioxide but would still contain sulfur, as H_2S, and other impurities, such as low levels of mercury, not yet removed in the process. Unshifted gas sent to the flare would contain large amounts of carbon monoxide, carbon dioxide and hydrogen and would also contain sulfur compounds, as carbonyl sulfide (COS), and the other impurities contained in the shifted gas.

[11] The process is continuous without any significant syngas or fuel storage capacity so any upsets require the gases to be vented to a flare while the source of the upset is corrected or the gasification system is shutdown.

predominately CO_2, is blended with the carbon dioxide stream that is piped offsite for CO_2 sequestration and EOR. The recovered sulfur is in the form of liquid elemental sulfur that would be trucked offsite as a secondary product. The overall sulfur recovery is estimated to range from 99.8 to 99.9+ percent.

The SRU tail gas thermal oxidizer would be operated to oxidize H_2S and other vent gas components that are generated during startup, shutdown, and other miscellaneous gasification unit streams (tank and equipment vents) during normal operation to prevent nuisance odors during operation.

The SRU unit also has fugitive emissions from the piping components from various VOC and CO laden streams, including the sulfur, tail gas treatment unit process, and tail gas treatment unit amine streams.

Air Separation Unit (ASU) and Gasification Cooling Towers

The ASU cooling tower would be located adjacent to the ASU unit and would reject waste heat from the ASU. The ASU cooling tower water recirculation rate would be approximately 40,200 gpm. The gasification cooling tower would reject waste heat from the gasification unit and would be co-located with the power block cooling tower. The gasification cooling tower water recirculation rate would be approximately with 42,300 gpm. The ASU and gasification block cooling towers would operate up to 8,322 hours annually. The cooling towers would operate with a maximum total dissolved solids (TDS) concentration of 9,000 ppmw and the cooling towers' particulate emissions would be controlled with high efficiency mist eliminators.

Carbon Dioxide Vent

The carbon dioxide vent would be used to release the produced CO_2 vent stream, which contains small amounts of CO, VOC, and H_2S when the exhaust compression, pipeline, or injection systems are unavailable. The CO_2 vent would be limited to 504 hours per year, which is the worst case venting assumption during early operation (first three years) and CO_2 venting is expected to occur no more than 120 hours per year during mature operations. Carbon dioxide emissions estimates in the Greenhouse gas (GHG) PSA section will include these emissions.

Dust Collection (Feedstock)

Enclosed Feedstock Handling and Storage

The enclosed feedstock (coke, coal, and fluxant[12]) and gasifier solids (slag/ash and unconverted carbon) materials handling operations would include bulk material unloading, loading, belt conveying, belt transfer points, silo loading, and reclaim. The feedstock handling emission sources would include the following six emissions units:

- Truck Feedstock Unloading
- Feedstock (Coke/Coal) Storage Silos (filling)

[12] Fluxant is a mineral based material added to the gasifier feed to adjust the ash melting temperature such that the desired molten gasification solids gravity flow occurs in the gasifier. Its composition is dependent on the coke/coal feedstock characteristics.

- Mass Flow Bins (in/out)
- Coke/Coal Silos (loadout)
- Grinder/Crusher
- Fluxant Bins (filling)

Inactive Open Coke Storage Pile

The project would include a large “inactive” coke storage pile that would provide at least 30 days of petcoke feedstock.[13] The storage pile is proposed to be covered with a stabilizer to reduce emissions.

Emergency Equipment

Emergency Diesel Generator

Two Tier 4 diesel emergency generators (2,922 HP) would be installed and each generator would operate for non-emergency use for up to 50 hours[14] per year.

Emergency Firewater Pump

A Tier 4 diesel firewater pump engine (556 HP) would be operated for non-emergency use for up to 100 hours per year.

Project Operating Emissions

The most significant emission source of the project would be the CTG and HRSG. The CTG would operate on hydrogen-rich syngas, natural gas and or a mixture of the two (45 to 90% hydrogen-rich syngas) over the CTG/HRSG power generation load range of 60 to 100 percent and the power block design would be optimized for three different performance cases. Minor emission sources would include two emergency diesel generators, one emergency firewater pump engine, the startup emissions from the thermal oxidizer and the three flares.

CTG HRSG Emissions

Startup and shutdown emissions for the proposed project’s CTG/HRSG would be higher than normal operating emissions. The CTG/HRSG would always be fired on natural gas for startup therefore the emission rates presented in **Air Quality Table 10** reflects natural gas startup and shutdown. Cold startup and hot startup would last for 3 hours and 1 hour, respectively. Shutdown would be completed in 30 minutes.

[13] In comparison, the enclosed storage provides 3 to 5 days worth of feedstock at maximum plant production rate. The inactive petcoke storage pile is not currently included in the District’s PDOC and no emission estimates for the open storage pile were provided by the applicant. This storage pile, if well controlled, should have negligible emissions, but this emission source will be updated as necessary in the FSA based on information presented in the FDOC.

[14] Revised from 52 hours/year to 50 hours/year per the District’s PDOC.

Air Quality Table 10
Summary of CTG/HRSG Startup and Shutdown Emissions, lbs/event

Pollutant	NOx	CO	VOC	SOx	PM10/PM2.5
Cold Startup (3-hours)	272.0	5,039.0	800.0	15.3	57.0
Hot Startup (1-hour)	167.0	394.0	98.0	5.1	19.8
Shutdown (30 minutes)	62.0	126.0	21.0	2.6	5.0

Source: URS 201Lk

The applicant estimated average normal CTG/HRSG operating emissions for each fuel type at annual average ambient temperature of 65 °F are presented in **Air Quality Table 11**.

Air Quality Table 11
Summary of Average Hourly CTG/HRSG Normal Operating Emissions, lbs/hr

Pollutant	NOx	CO	VOC	SOx	PM10/PM2.5
Fired on Natural Gas	35.1	26.7	6.1	4.9	18.0
Fired on Hydrogen-Rich Fuel	39.7	18.1	3.5	6.8	19.8
Co-Firing	39.7	30.2	6.9	6	19.8

Source: URS 2010L

Maximum short-term operational emissions from the CTG/HRSG were determined from a comparative evaluation of potential emissions corresponding to normal operating conditions, and CTG startup/shutdown conditions. **Air Quality Table 12** presents worst case hourly emissions for each fuel type. For natural gas firing, the worst case NOx and PM10/2.5 emissions reflect emissions during hot startup, and emissions of all the other pollutants reflect 1 hour of cold startup. The worst case short term emissions for the project would be the same as maximum emissions for natural gas firing.

Air Quality Table 12
Summary of Worst Case Hourly CTG/HRSG Emissions, lbs/hour

Pollutant	NOx	CO	VOC	SOx	PM10/PM2.5
Fired on Natural Gas	167.0	1,679.7	266.7	5.1	19.8
Fired on Hydrogen-Rich Fuel	39.7	18.1	3.5	6.8	19.8
Co-Firing	39.7	30.2	6.9	6	19.8
Project Maximum	167.0	1,679.7	266.7	6.8	19.8

Source: URS 2010L

Due to limited operating experience with both hydrogen-rich gas and natural gas combustion in a common combustor, the District has called for “target” emissions levels for NOx, CO and VOC emissions and lower BACT-level emissions. Final emissions requirements would be determined after initial operation. Worst case impacts are estimated using the higher “target” emissions rates.

Site Maintenance and Feedstock Transportation Emissions

The project requires 10 light heavy-duty gasoline trucks and 10 light heavy-duty diesel trucks for onsite maintenance. The applicant expects a maximum of 27 Vehicle Miles Traveled (VMT) per day per vehicle, and 10,000 VMT per year per vehicle. Onsite Operations and Maintenance (O&M) emissions would also include emissions from onsite truck travel for coke and coal, and onsite gasifier solids handling. These onsite non-stationary source emissions are presented in **Air Quality Table 13**.

Air Quality Table 13
Summary of Non-Stationary Source Emissions

	NOx	CO	VOC	SOx	PM10	PM2.5
Daily Emissions (lbs/day)						
O&M Vehicle	0.444	0.693	0.060	0.010	0.280	0.032
Coke & Coal Trucks	7.825	3.221	0.909	0.015	0.139	0.045
Gasifier Solids Handling	1.143	0.509	0.105	0.002	0.015	0.005
Employee Vehicle	5.405	49.79	1.516	0.056	0.500	0.262
Total	14.817	54.218	2.589	0.082	0.934	0.344
Annual Emissions (ton/year)						
O&M Vehicle	0.081	0.127	0.011	0.002	0.051	0.006
Coke & Coal Trucks	0.772	0.318	0.090	0.002	0.014	0.004
Gasifier Solids Handling	0.044	0.020	0.006	0.000	0.001	0.000
Employee Vehicle	0.986	9.087	0.277	0.010	0.091	0.048
Total	1.883	9.551	0.383	0.014	0.157	0.058

Source: URS 2010m

The Project would utilize petcoke from various refineries in the Carson Area, the Santa Maria Area, and the Bakersfield Area. Currently, a portion of this petcoke is transported to the Port of Long Beach either by trucks or via railway, then shipped to Asia. As the project starts operating this petcoke would be delivered by trucks to the project site rather than to the Port of Long Beach. Coal would be transported by rail from mines in the western United States to a nearby transloading terminal within Kern County. **Air Quality Table 14** presents feedstock transportation emissions for the project site and current-practice scenarios, and the resulting net emissions due to the proposed project in the San Joaquin Valley Air Basin.

Air Quality Table 14
Net Emission Difference in Feedstock Transportation - SJVAB, ton/year

	NOx	CO	VOC	SOx	PM10	PM2.5
Current-Practice Scenario						
Route 1 (CA Petcoke, Santa Maria Area)	---	---	---	---	---	---
Route 2 (CA Petcoke, Carson Area)	---	---	---	---	---	---
Route 3 (CA Petcoke, Bakersfield Area)	1.61	0.55	0.13	0.003	0.07	0.06
Route 4 (CA Petcoke, Bakersfield Area)	8.86	3.01	0.72	0.02	0.38	0.31
Misc. Trucks	---	---	---	---	---	---
Coal	---	---	---	---	---	---
Basin Total	10.47	3.56	0.85	0.023	0.45	0.37
Proposed Project Scenario						
Route 1 (CA Petcoke, Santa Maria Area)	5.93	2.81	0.60	0.04	0.30	0.21
Route 2 (CA Petcoke, Carson Area)	4.95	2.34	0.50	0.03	0.25	0.17
Route 3 (CA Petcoke, Bakersfield Area)	0.26	0.12	0.03	0.0017	0.01	0.01
Route 4 (CA Petcoke, Bakersfield Area)	0.26	0.12	0.03	0.0017	0.01	0.01
Misc. Trucks	1.75	0.83	0.18	0.01	0.09	0.06
Coal	3.86	1.03	0.28	0.28	0.15	0.13
Basin Total	17.01	7.25	1.61	0.36	0.82	0.58
Net Emissions Increase	6.54	3.69	0.77	0.34	0.37	0.21

Source: HEI 2009c

As shown in **Air Quality Table 14**, the net emissions for fuel transportation within the SJVAB are expected to increase for all criteria pollutants.

A feedstock transportation comparison and net emission estimates were also performed by the applicant for the South Coast, the South Central Coast, and the Mojave Desert Air Basins as presented in the **Air Quality Table 15**.

Air Quality Table 15
Net Emission Difference in Feedstock Transportation – South Coast, South Central Coast, and Mojave Desert Air Basins, ton/year

	NOx	CO	VOC	SOx	PM10	PM2.5
Current-Practice Scenario						
South Coast Basin Total	27.15	6.17	1.77	0.03	1.06	0.95
South Central Coast Air Basin Total	20.55	3.76	1.19	2.04	0.72	0.66
Mojave Desert Air Basin Total	0.00	0.00	0.00	0.00	0.00	0.00
Proposed Project Scenario						
South Coast Basin Total	8.38	4.09	0.77	0.03	0.47	0.34
South Central Coast Air Basin Total	8.84	4.42	1.11	0.00	0.55	0.55
Mojave Desert Air Basin Total	18.50	3.37	1.05	0.01	0.65	0.60
Net Emission Difference						
South Coast Basin Total	(18.76)	(2.08)	(1.00)	0.01	(0.59)	(0.62)
South Central Coast Air Basin Total	(11.71)	0.66	(0.08)	(2.04)	(0.17)	(0.11)
Mojave Desert Air Basin Total	18.50	3.37	1.05	0.01	0.65	0.60

Source: HEI 2009c

Project Total Emissions

Air Quality Table 16 presents worst case daily emissions for the entire facility. The following assumptions are used to derive the worst case daily emissions

- For NOx, CO, and VOC power block maximum daily emissions, 1 cold startup, 1 hot startup, 1 shutdown and 19.5 hours of normal co-firing operation at 20°F during winter time are assumed.
- The maximum daily power block emissions of SOx and PM10/2.5 reflect continuous 24 -hour normal operation. Daily SOx emissions would be the highest when fired on hydrogen-rich gas at the yearly average of 65°F. Daily PM10/2.5 emissions would be the highest when fired either on hydrogen-rich gas at 65°F or co-fired at 20°F.
- The three cooling towers, three flares, the auxiliary boiler, the tail gas thermal oxidizer, the CO_2 vent, and the gasifier are assumed to operate 24 hours/day.
- Each of the emergency generators and the fire pump is assumed to operate 2 hours/day.
- 24-hour continuous operation of feedstock handling and storage system is assumed at the hourly throughput rate of 775 ton/hr for truck unloading and coke/coal silos filling, 170 ton/hr for mass flow bins (in/out), coke/coal silos loadout, and crusher inlet/outlet, and 40 ton/hr for fluxant bins.

Air Quality Table 16
Summary of Worst Case Daily Emissions – Stationary Sources, lbs/day

Pollutant	NOx	CO	VOC	SOx	PM10	PM2.5
Power Block - Maximum	1,320.0	6,183.0	1,061.4	163.2	475.2	475.2
Power Block Cooling Tower	--	--	--	--	94.50	56.70[b]
Process Area Cooling Tower	--	--	--	--	22.84	13.71[b]
ASU Cooling Tower	--	--	--	--	21.71	13.02[b]
Auxiliary Boiler	20.45	126.10	13.63	9.71	17.04	17.04
Emergency Generators	12.88	67.00	7.74	0.12	1.80	1.80
Fire Water Pump	3.68	6.37	0.34	0.01	0.04	0.04
Gasification Flare	2,849.0	15,052.6	0.02	113.9	0.04	0.04
SRU Flare	52.66	35.18	0.61	221.71	1.32	1.32
Rectisol Flare	0.86	0.58	0.01	0.01	0.02	0.02
SRU/Tail Gas Thermal Oxidizer[a]	57.60	48.20	35.49	48.00	1.92	1.92
CO_2 Vent	--	10,180.88	232.71	--	--	--
Gasifier[a]	207.36	302.40	132.3	1.76	6.91	6.91
Feedstock – Dust Collection	--	--	--	--	42.42	12.30
Total	**4,524.49**	**32,002.31**	**1,484.25**	**558.42**	**685.76**	**600.02**

Source: URS 2010L, SJVAPCD 2010c, Staff Interpretation
Notes:
[a] – Includes VOC fugitive emissions from hydrocarbon stream piping components per the PDOC.
[b] – The applicant and District have assumed that PM2.5 emissions are 60 percent of the total cooling tower emissions. Staff is not certain that this assumption is technically valid and has asked the District to verify the use of any particulate size fractions for the cooling towers.

Annual facility emission estimates, including the non-stationary source and net SJVAB feedstock transportation emissions, are provided in **Air Quality Table 17**, and are based the following assumptions:

- For the power block 10 cold startups, 20 hot startups, 30 shutdowns, and the balance of normal operation (8,257 hours) fired on each fuel type.
- All three cooling towers are assumed to operate 8,322 hours/year.
- The auxiliary boiler is assumed to operate 2,190 hours/year.
- Each of the emergency generator engines would operate 50 hours/year and the fire pump would operate for 100 hours/year.
- All three flares would have their natural gas fueled pilots operating 8,760 hours per year and each flare would operate with vented gases as follows: gasification flare – 196,500 MMBtu/hr heat input; SRU Flare – 40 hours @ 36 MMBtu/hr heat input, and Rectisol Flare – pilot emissions only.
- Tail gas oxidizer would operate for 8,760 hours/year.
- The CO_2 vent use is limited to 504 hours/year.
- The gasifier heaters operate 1,200 hours/year each (3,600 hours/year total).
- For feedstock handling the maximum annual emissions are estimated based on 8,760 hours/year and the annual average throughput of 150 ton/hr for truck unloading, coke/coal silos filling, mass flow bins (in/out), coke/coal silos (loadout), and crusher inlet/outlet. For fluxant bins, process weight of 6 tons/hr is assumed for 8,760 hours/year.

Air Quality Table 17
Summary of Annual Operating Emissions, ton

Pollutant	NOx	CO	VOC	SOx	PM10	PM2.5
Stationary Emission Sources						
Power Block						
Fired on Natural Gas	148.87	141.26	30.48	20.40	74.87	74.87
Fired on Hydrogen-Rich Fuel	167.86	105.75	19.74	28.24	82.30	82.30
Co-Firing	167.86	155.71	33.78	24.94	82.30	82.30
Facility Total						
Power Block – Maximum	167.86	155.71	33.78	28.24	82.30	82.30
Power Block Cooling Tower	--	--	--	--	16.40	9.83[b]
Process Area Cooling Tower	--	--	--	--	3.96	2.38[b]
ASU Cooling Tower	--	--	--	--	3.77	2.26[b]
Auxiliary Boiler	0.93	5.75	0.62	0.44	0.78	0.78
Emergency Generators	0.16	0.84	0.10	0.00	0.02	0.02
Fire Water Pump	0.09	0.16	0.01	0.0003	0.001	0.001
Gasification Flare	7.15	111.17	0.003	0.12	0.01	0.01
SRU Flare	0.24	0.16	0.002	0.37	0.01	0.004
Rectisol Flare	0.16	0.11	0.002	0.003	0.004	0.004
SRU/Tail Gas Thermal Oxidizer[a]	10.51	8.79	6.48	8.76	0.33	0.33
CO_2 Vent	--	106.90	2.44	--	--	--
Gasifier[a]	7.78	11.3	15.62	0.07	0.25	0.25
Feedstock – Dust Collection	--	--	--	--	3.71	1.0
Subtotal	**194.89**	**400.89**	**59.05**	**38.01**	**111.53**	**99.17**
Non-Stationary Emission Sources						
Onsite Non-Stationary Emissions	1.9	9.551	0.383	0.014	0.157	0.058
Fuel Transportation in SJVAB (Net)	6.5	3.69	0.77	0.34	0.37	0.21
Subtotal	**8.4**	**13.241**	**1.153**	**0.354**	**0.527**	**0.268**
Project Total	**203.29**	**414.13**	**60.20**	**38.36**	**112.06**	**99.44**

Source: HEI 2009c, URS 2010L
Notes:
[a] – Includes VOC fugitive emissions from hydrocarbon stream piping components per the PDOC.
[b] – The applicant and District have assumed that PM2.5 emissions are 60 percent of the total cooling tower emissions. Staff is not certain that this assumption is technically valid and has asked the District to verify the use of any particulate size fractions for the cooling towers.

The District's emission estimate in the PDOC includes a maximum emission estimate based on the applicant's gas turbine emission rates and a target emission rate based on the District's target emission rates for the gas turbine. Staff has presented the maximum emission rates as they are the basis for the project's offset requirements.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Energy Commission staff assesses four kinds of primary and secondary[15] impacts: construction, operation, closure and decommissioning, and cumulative. Construction impacts result from the onsite and offsite emissions occurring during site preparation and construction of the proposed project. Operation impacts result from the emissions of the proposed project during operation, which includes all of the onsite equipment emissions (gas turbine, auxiliary boiler, flares, cooling towers, emergency engines, etc.),

[15] Primary impacts potentially result from facility emissions of NOx, SOx, CO and PM10/2.5. Secondary impacts result from air contaminants that are not directly emitted by the facility but formed through reactions in the atmosphere that result in ozone, and sulfate and nitrate PM10/PM2.5.

the onsite maintenance vehicle emissions, and the offsite employee and fuel delivery trip emissions. Closure and decommissioning impacts occur from the onsite and offsite emissions that would result from dismantling the facility and restoring the site. Cumulative impacts analysis assesses the impacts that result from the proposed project's incremental effect viewed over time, together with other closely related past, present, and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project. (Pub. Resources Code § 21083; Cal. Code Regs., tit. 14, §§ 15064(h), 15065(c), 15130, and 15355.)

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Energy Commission staff evaluates potential impacts per Appendix G of the CEQA Guidelines (CCR 2006). A CEQA significant adverse impact is determined to occur if potentially significant CEQA impacts cannot be mitigated through the adoption of Conditions of Certification. Specifically, Energy Commission staff uses health-based ambient air quality standards (AAQS) established by the ARB and the U.S. EPA as a basis for determining whether a project's emissions will cause a significant adverse impact under CEQA. The ambient air quality standards are set at levels that include a margin of safety and are designed to adequately protect the health of all members of the public, including those most sensitive to adverse air quality impacts such as the aged, people with existing illnesses, children, and infants. Staff evaluates the potential for significant adverse air quality impacts by assessing whether the project's emissions of criteria pollutants and their precursors (NOx, VOC, PM10 and SO_2) could create a new AAQS exceedance (emission concentrations above the standard), or substantially contribute to an existing AAQS exceedance.

Staff evaluates both direct and cumulative impacts. Staff will find that a project or activity will create a direct adverse impact when it causes an exceedance of an AAQS. Staff will find that a project's effects are cumulatively considerable when the project emissions in conjunction with ambient background, or in conjunction with reasonably foreseeable future projects, substantially contribute to ongoing exceedances of an AAQS. Factors considered in determining whether contributions to ongoing exceedances are substantial include:

1. the duration of the activity causing adverse air quality impacts;

2. the magnitude of the project emissions, and their contribution to the air basin's emission inventory and future emission budgets established to maintain or attain compliance with AAQS;

3. the location of the project site, i.e., whether it is located in an area with generally good air quality where non-attainment of any ambient air quality standard is primarily or solely due to pollutant transport from other air basins;

4. the meteorological conditions and timing of the project impacts, i.e., do the project's maximum modeled pollutant impacts occur when ambient concentrations are high (such as during high wind periods, or seasonally);

5. the modeling methods, and how refined or conservative the impact analysis modeling methods and assumptions were and how that may affect the determined adverse impacts;

6. the project site location and nearest receptor locations; and whether the identified adverse impacts would also occur at the maximum impacted receptor location; and,

7. the potential for future cumulative impacts; and whether appropriate mitigation is being recommended to address the potential for impacts associated with likely future projects.

For construction emissions, the mitigation that is considered is limited to controlling both construction equipment tailpipe emissions and fugitive dust emissions to the maximum extent feasible. For operating emissions, the mitigation considered includes both feasible emission controls (BACT) and the use of emission reduction credits to offset emissions of nonattainment criteria pollutants and their precursors.

DIRECT/INDIRECT IMPACTS AND MITIGATION

While the emissions are the actual mass of pollutants emitted from the project, the impacts are the concentration of pollutants from the project that reach the ground level. When emissions are expelled at a high temperature and velocity through the relatively tall stack, the pollutants will be significantly diluted by the time they reach ground level. The emissions from the proposed project are analyzed through the use of air dispersion models to determine the probable impacts at ground level.

Air dispersion models provide a means of predicting the location and ground level magnitude of the impacts of a new emissions source. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions to provide theoretical maximum offsite pollutant concentrations for short-term (1-hour, 3-hour, 8-hour, and 24-hour) and annual periods. The model results are generally described as maximum concentrations, often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$).

The applicant used the U.S. EPA guideline ARMS/EPA Regulatory Model (AERMOD) to estimate ambient impacts from project construction and operation. The construction emission sources for the site were grouped into two categories: equipment (off-road equipment); and vehicles (on-road equipment), where the exhaust and fugitive dust emissions for each type were calculated for particulate matter modeling. The equipment exhausts were modeled as point sources and fugitive dust emissions were modeled as areas sources. Similar modeling procedures were used by the applicant to determine impacts from the operating emissions stationary sources, maintenance vehicle exhaust, and fugitive dust emissions.

In general, the inputs for the modeling include stack information (exhaust flow rate, temperature, and stack dimensions), specific turbine emission data, meteorological data, (wind speed and atmospheric conditions), and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured at the Bakersfield Airport meteorological station, located in the city of Bakersfield, within 20 miles east-northeast of the Project site.

For the determination of one-hour average and annual average construction NOx concentrations the Ozone Limiting Method (OLM) was used to determine worst-case near field NO_2 impacts. The NOx emissions from internal combustion sources, such as diesel engines, are primarily in the form of nitric oxide (NO) rather than NO_2. The NO converts into NO_2 in the atmosphere, primarily through the reaction with ambient ozone, and NOx OLM assumes full conversion of stack NO emissions with the available ambient ozone. The NOx OLM method was used assuming an initial NO_2/NOx ratio of 0.1 for all NOx emission sources. Actual monitored hourly background ozone concentration data from Bakersfield for 2004 to 2008 were used to provide ozone data that corresponds to the years of meteorological data that were used to calculate maximum potential NO to NO_2 conversion to determine the maximum hourly NO_2 impacts.

The applicant has also provided a modeling analysis to show compliance during operation with the new federal 1-hour NO_2 standard (URS 2010L). This modeling analysis, also using the AERMOD dispersion model, includes the use of the NOx OLM modeling option and used a post-processor developed by the applicant's consultant to also add in the corresponding hourly NO_2 background data and determine the 98^{th} percentile of daily maximums (eighth highest) for each modeled receptor location. The NOx OLM option considers that the emissions of NOx are initially primarily in the form of NO that over time oxidizes, primarily through a reaction with ozone, to NO_2. The initial NO_2/NOx ratio was set at the default value of 0.1 and the conversion of the rest of the NO to NO_2 is assumed to be limited by the hourly ambient ozone concentration. For this modeling analysis the applicant obtained hourly monitored ozone and NO_2 concentration data from Bakersfield, concurrent with the 2005 to 2008 meteorological data from Bakersfield (2004 NO_2 pollutant data was not complete enough for use).

Staff reviewed the background concentrations provided by the applicant, replacing them where appropriate[16] with the available highest ambient background concentrations from the last three years at the most representative monitoring stations as show in **Air Quality Table 5**. Staff added the modeled impacts to these background concentrations, and then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the proposed project's emission impacts would cause a new exceedance of an ambient air quality standard or would contribute to an existing exceedance.

The following sections discuss the proposed project's short-term direct construction and operation ambient air quality impacts as estimated by the applicant, and describes appropriate mitigation measures.

[16] This does not include the background for the federal 1-hour NO_2 standard since the applicant's modeling analysis uses actual monitored NO_2 concentrations to determine the combined project plus background average 98^{th} percentile 1-hour NO_2 impacts.

Construction Impacts and Mitigation

Construction Modeling Analysis

The applicant modeled the construction emissions of the proposed project using the AERMOD (version 07026). The fugitive dust emissions sources within the site are modeled as area sources. Equipment exhaust emissions of gaseous pollutants and particulates are modeled as a series of point sources.

For the determination of one-hour average construction NOx concentrations the applicant used an Ozone Limiting Method calculation that multiplied the maximum modeled NOx value by the assumed initial NO_2/NOx ratio of 0.1 for diesel equipment and added the conversion of NO to NO_2 based on the background ozone concentration that corresponded to the maximum NOx impact hour.

To determine the construction impacts on short-term ambient standards (i.e. 1-hour through 24 hours) the worst-case daily on-site construction emission levels shown in **Air Quality Table 6** were modeled. For pollutants with annual average ambient standards, the applicant used the summation of overall construction activities for the consecutive 12-month period that would produce the highest emissions of all pollutants. Modeling assumed that all of the equipment would operate from 6 am to 4 pm daily. **Air Quality Table 18** provides the results of this modeling analysis of construction impacts.

AIR QUALITY Table 18
HECA Construction Impacts, (μg/m^3)

Pollutant	Averaging Period	Project Impact (μg/m^3)	Background (μg/m^3) [b]	Total Impact (μg/m^3)	Limiting Standard (μg/m^3)	Type of Standard	Percent of Standard
NO_2 [a]	1 hour	146.3	190.2	336.5	339	CAAQS	99%
	annual	3.7	26.6	30.3	57	CAAQS	53%
PM10	24 hour	27.7	115.0	142.7	50	CAAQS	285%
	annual	5.3	55.4	60.7	20	CAAQS	304%
PM2.5	24 hour	6.5	73.0	79.5	35	NAAQS	227%
	annual	1.4	22.0	23.4	12	CAAQS	195%
CO	1 hour	130	4,025	4,155	23,000	CAAQS	18%
	8 hour	31	2,411	2,442	10,000	CAAQS	24%
SO_2	1 hour	0.28	62.9	63.2	655	CAAQS	10%
	3 hour	0.18	56.6	56.8	1,300	NAAQS	4%
	24 hour	0.03	18.4	18.4	105	CAAQS	18%

Source: URS 2009k
[a] One-hour NOx value was determined using Ozone Limiting Method calculation.
[b] Background values have been adjusted per staff recommended background concentrations shown in **AIR QUALITY Table 5**.

The applicant's modeling results indicate that the project's construction impacts would not create violations of NO_2, SO_2 or CO standards, but could further exacerbate violations of the PM10 and PM2.5 standards. In light of the existing PM10 and PM2.5 nonattainment status for the project site area, staff considers the modeled impacts of PM and PM precursors to be significant and, therefore, require mitigation.

Construction Mitigation

As described in the “Laws, Ordinances, Regulations, and Standards” section, District Regulation VIII (i.e. Series 8000) limits fugitive dust emissions during the construction phase of a project. Staff recommends that construction emission impacts be mitigated to the greatest feasible extent including all feasible measures from the LORS, as well as other measures considered necessary by staff to fully mitigate the construction emissions.

Applicant’s Proposed Mitigation

The applicant’s construction emissions estimates in **Air Quality Tables 6** and **7** and construction modeling results in **Air Quality Table 18** assume the use of following emission control measures (URS 2009c).

Fugitive Dust Emissions Mitigation

- Construction roads and work area would be watered as needed.
- Entry ways into the project site would be graveled or treated with dust suppressant.
- Equipment tires shall be inspected and cleaned free of dirt prior to leaving the construction site.
- Long-term soil storage stock piles would be treated with dust suppressants or covered.
- Construction vehicles used for bulk material transport on public roadways will be covered or the materials would be wetted during load out.

Engine Emissions Mitigation

- The construction equipment would be maintained and tuned in accordance to the engine manufacturer’s specifications.
- Construction equipment would be fueled with ultra-low sulfur diesel.
- Electric welders, electric air compressors, and other electric construction equipment would be used as much as practical to reduce the requirement for combustion engine operated equipment.
- Soot filters would be used on heavy construction equipment where it is practical for the engine type.
- Diesel-heavy construction equipment shall not remain running at idle for more than 5 minutes, to the extent practical.

Adequacy of Proposed Mitigation

The applicant’s revised PM10 emission estimate assumes a very aggressive control efficiency factor for fugitive dust from unpaved roads, which staff believes to be potentially overly optimistic. However, even using these optimistic emissions factors, the modeling analysis shows that the mitigated construction PM10 impacts are predicted to be potentially significant beyond the project fence line. Therefore, staff believes that all reasonable feasible construction emission mitigation measures are needed to mitigate the potentially significant construction PM10 impacts.

The applicant's proposed engine emissions mitigation has some of the mitigation measures that staff normally recommends, but does not include adequate ozone precursor (NOx and VOC) mitigation.

Staff Proposed Mitigation

Staff recommends construction fugitive dust and engine emissions mitigation measures beyond those proposed by the applicant, that aren't already regulatory requirements (such as use of ARB low sulfur diesel), and also include several additional construction fugitive dust PM10 emission mitigation measures and construction equipment mitigation measures to assure maximum feasible fugitive dust control performance and construction equipment exhaust emissions control, as well as compliance assurance measures in Conditions of Certification **AQ-SC1** through **AQ-SC5**.

Staff recommends **AQ-SC1** to require the applicant to have an onsite construction mitigation manager who will be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the construction mitigation program would be provided in the monthly construction compliance report that is required in staff's recommended Condition of Certification **AQ-SC2**.

Staff incorporated and augmented the applicant's proposed fugitive dust mitigation measures and recommends that the fugitive dust mitigation measures be formalized in Condition of Certification **AQ-SC3**. **AQ-SC3** includes several additional mitigation measures to control fugitive dust emissions and requires that District Regulation VIII rule requirements apply when they are more stringent.

Staff recommends Condition of Certification **AQ-SC4** to limit the potential offsite impacts from visible dust emissions from the construction activities.

Staff recommends Condition of Certification **AQ-SC5** to require the use of new off-road equipment that would meet at a minimum U.S. EPA/ARB Tier 3 emissions levels that would significantly reduce the NOx and diesel particulate emissions from off-road equipment.

Based on the relatively short-term nature of the worst-case construction impacts, and staff's recommendation of requiring all feasible construction emission mitigation measures, staff believes that the construction air quality impacts will be less than significant with the implementation of the mitigation measures contained in the recommended Conditions of Certification.

Operation Impacts and Mitigation

The following section discusses the project's direct ambient air quality impacts as estimated by the applicant and evaluated by staff. Additionally, this section discusses the recommended mitigation measures.

Operational Modeling Analysis

The applicant performed direct impact modeling analyses, including normal operations, fumigation, and initial commissioning impact modeling.

A refined dispersion modeling analysis was performed to identify off-site criteria pollutant impacts that would occur from routine operational emissions throughout the life of the project. This impact analysis includes both maximum operating and start-up/shutdown scenarios to determine worst-case air quality impacts on both a short-term and an annual basis. The operating profiles are shown in **Air Quality Table 10** to **Air Quality Table 17**. These conditions were then modeled to determine the worst case short term impacts. The predicted maximum concentrations of non-reactive pollutants are summarized in **Air Quality Table 19**.

Air Quality Table 19
HECA Operating Impacts, (µg/m³)

Pollutant	Averaging Period	Project Impact (µg/m³)	Background (µg/m³) [a]	Total Impact (µg/m³)	Limiting Standard (µg/m³)	Type of Standard	Percent of Standard
NO_2	1 hour State	133.7	190.2	323.9	339	CAAQS	96%
	1 hour Fed	[b]	[b]	177.0 [b]	188	NAAQS	94%
	annual	0.66	26.6	27.3	57	CAAQS	48%
PM10	24 hour	4.1	115.0	119.1	50	CAAQS	238%
	annual	0.6	55.4	56.0	20	CAAQS	280%
PM2.5	24 hour	2.6	73.0	75.6	35	NAAQS	216%
	annual	0.4	22.0	22.4	12	CAAQS	187%
CO	1 hour	2,180	4,025	6,205	23,000	CAAQS	27%
	8 hour	576	2,411	2,987	10,000	CAAQS	30%
SO_2	1 hour State	26.5	62.9	89.4	655	CAAQS	14%
	1 hour Fed	26.5	18.3	44.8	197	NAAQS	23%
	3 hour	15.9	56.6	72.5	1,300	NAAQS	6%
	24 hour	1.8	18.4	20.2	105	CAAQS	19%

Source: URS 2010L
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.
[b] The hourly project impact and hourly NO_2 background data were combined for this standard to determine the three year average of the 98th percentile of the maximum daily 1-hour values (2006-2008).

The applicant's modeling results indicate that the project's normal operational impacts would not create violations of the NO_2, SO_2 or CO standards, but could further exacerbate violations of the PM10 and PM2.5 standards. In light of the existing PM10 and PM2.5 nonattainment status for the project site area, staff considers the modeled impacts of PM and PM precursors to be significant and, therefore, require mitigation.

Fumigation Modeling Impact Analysis

There is the potential that higher short-term concentrations may occur during fumigation conditions. During the early morning hours before sunrise, the air is usually very stable. During such stable meteorological conditions, emissions from elevated stacks rise through this stable layer and are dispersed aloft. When the sun first rises, the air at ground level is heated, resulting in a vertical (both rising and sinking air) mixing of air for a few hundred feet or so. Emissions from a stack that enter this vertically mixed layer of air will also be vertically mixed, bringing some of those emissions down to the ground level. Later in the day, as the sun continues to heat the ground, this vertical mixing layer becomes higher and higher, and the emissions plume becomes better dispersed. The early morning pollution event, called fumigation, usually lasts approximately 30 to 90 minutes.

Fumigation conditions are generally only compared to one-hour standards. The applicant analyzed the maximum one-hour and three-hour air quality impacts under fumigation conditions from the CTGs/HRSG unit, auxiliary CTG, tail-gas thermal oxidizer, and gasifier refractory heater, using the SCREEN3 model (URS 2009b). The results of the analysis, as shown in **Air Quality Table 20**, indicate that the maximum one-hour fumigation impacts would be lower than the maximum operating emission impacts under normal meteorological conditions, as shown above in **Air Quality Table 19**.

Air Quality Table 20
Maximum HECA Fumigation Impacts, (μg/m^3)

Pollutant	Averaging Period	Project Impact (μg/m^3)	Background (μg/m^3) [a]	Total Impact (μg/m^3)	Limiting Standard (μg/m^3)	Type of Standard	Percent of Standard
NO_2	1 hour	83.5	190.2	273.7	339	CAAQS	81%
PM10	24 hour	3.9	115.0	118.9	50	CAAQS	238%
PM2.5	24 hour	3.9	73.0	76.9	35	NAAQS	220%
CO	1 hour	522	4,025	4,547	23,000	CAAQS	20%
	8 hour	261	2,411	2,672	10,000	CAAQS	27%
SO_2 [c]	1 hour	9.3	62.9	72.2	655	CAAQS	11%
	3 hour	6.2	56.6	62.8	1,300	NAAQS	5%
	24 hour	3.6	18.4	22.0	105	CAAQS	21%

Source: URS 2009b
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.

Initial Commissioning Short-Term Modeling Impact Analysis

The applicant modeled the commissioning emissions, which are significantly higher than the normal operating emissions to determine worst-case short-term operating impacts for the project. However, emissions of SOx, PM10 and PM2.5 depend primarily on the fuel use; therefore, emissions of these pollutants during commissioning are not expected to be higher than those during the normal operation.

The applicant presented several initial commissioning activities that would occur prior to meeting normal emission limits. The worst case emissions for the short-term NOx and CO impacts, as provided in the discussion prior to **Air Quality Table 8**, were determined and modeled.

The AERMOD model was used for the applicant's modeling analysis. The results of the commissioning emissions modeling analysis are shown in **Air Quality Table 21.** As shown in the table below the, the worst-case emissions would not cause an exceedance of the one-hour NO_2 standard or the one-hour and eight-hour CO standards. Therefore, the modeling results indicate that the commissioning emissions, and by comparison the startup emission impacts, do not have the potential to cause significant short-term ambient air quality impacts. Since they are limited-term activities, there was no need to evaluate commissioning activities relative to the federal short-term standard, which is based upon a 3-year average.

Air Quality Table 21
Maximum HECA Initial Commissioning Impacts[a]

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$) [b]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Type of Standard	Percent of Standard
NO_2	1 hour	120.9	190.2	311.1	339	CAAQS	92%
CO	1 hour	1,828	4,025	5,853	23,000	CAAQS	25%
CO	8 hour	335	2,411	2,746	10,000	CAAQS	27%

Source: HEI 2009c
[a] These max impacts include Auxiliary CTG (LMS 100 gas turbine) operation. The commissioning modeling analysis was not revised after the elimination of the Auxiliary CTG.
[b] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.

Visibility Impacts

A visibility analysis of the project's gaseous emissions is required under the federal Prevention of Significant Deterioration (PSD) permitting program. HECA is subject to PSD permitting through the U.S. EPA, because it would exceed the PSD major source emission thresholds for NO_2 and CO. For new PSD sources, an air quality related values (AQRVs) and visibility analysis is required for Class I areas located within 100 kilometers of a PSD project site. While the U.S. EPA is the PSD permitting lead, the review of the Class I modeling analysis is completed by the representative of the Federal Land Manager (the representative of the agency of jurisdiction for the Class I area). The only Class I area within 100 kilometers of the HECA project site is the San Rafael Wilderness, located approximately 31 miles southwest of the project site. The applicant provided a CALPUFF modeling analysis in the AFC (HEI 2009c) and later a revised analysis as part of the Data Response and Issues Resolution Workshop responses (URS 2010L). The results of this modeling analyses found that the impacts are below the Class I increments for the AQRVs and below the screening visibility impact significance thresholds. Therefore, Energy Commission staff anticipates that the project's AQRVs and visibility impacts on Class I areas would be considered less than significant by the U.S. EPA and Federal Land Managers. The PSD permit analysis conducted by the U.S. EPA will address these impacts.

Operations Mitigation

Applicant's Proposed Mitigation

Emission Controls

As discussed in the project description section, the applicant proposes to employ water injection, SCR with ammonia injection, CO catalyst, and operate exclusively on hydrogen-rich fuel created onsite and pipeline quality natural gas to limit turbine emission levels (HEI 2009c). The AFC (HEI 2009c) and PDOC (SJVAPCD 2010c) provide the following BACT emission limits:

CTG/HRSG Combustion Turbine (excluding Start up/Shutdown conditions)

- NOx: 4.0 ppmvd at 15 percent O_2 on hydrogen-rich fuel and natural gas fuel (3-hour average). The PDOC identifies target emission levels of 2.0 ppmvd (3-hour average) and 2.5 ppmvd (1-hour average)
- CO: 3.0 ppmvd at 15 percent O_2 on hydrogen-rich fuel, 5 ppmvd at 15 percent O_2 on natural gas fuel. The PDOC identifies target emission levels of 3.0 ppmvd and 4.0 ppmvd (3-hour average) for hydrogen-rich and natural gas fuels, respectively.
- VOC: 1 ppmvd at 15 percent O_2 on hydrogen-rich fuel and 2 ppm at 15 percent O_2 on natural gas fuel. The PDOC identifies target emission levels of 1.0 ppmvd and 1.5 ppmvd (3-hour average) for hydrogen-rich and natural gas fuels, respectively.
- PM10: 19.8 lb/hr on hydrogen-rich fuel, 18 lb/hr on natural gas fuel (both duct firing).
- SO_2: less than 5 ppmvd in undiluted total sulfur on hydrogen-rich fuel, less than 0.75 grain/100scf (12.65 ppm) on natural gas fuel.
- NH_3: 5 ppmvd at 15 percent O_2 on hydrogen-rich fuel and natural gas fuel.

For NOx, CO, and VOC the District is proposing to give the applicant two years to meet the target emission rate levels, and if the target levels cannot be achieved then BACT will be determined based on what is found to be achievable, but not higher an emissions rate than the applicant's proposed BACT levels.

Cooling Towers

- PM10: 0.0005% drift as percent of the amount of recirculating water.

Auxiliary Boiler, Natural Gas 142 MMBtu/hr

The applicant proposes an ultra-low NOx burner and flue gas recirculation to control NOx, and operate exclusively on pipeline quality natural gas to limit emission levels (HEI 2009c). The AFC (HEI 2009c) and PDOC (SJVAPCD 2010c) provide the following BACT emission limits:

- NOx: 5 ppmvd at 3 percent O_2 (0.0060 lb/MMBtu heat input)
- CO: 50.8 ppmvd at 3 percent O_2 (0.037 lb/MMBtu heat input)
- VOC: 9.5 ppm at 3 percent O_2 (0.004 lb/MMBtu heat input)
- PM10: 0.005 lb/MMBtu heat input
- SO_2: 0.00285 lb/MMBtu heat input

Two Emergency Diesel Generators, 2,922 hp (Tier 4 engines)

- NOx: 0.5 gram/bhp/hr

- CO: 0.29 gram/bhp/hr
- VOC: 0.11gram/bhp/hr
- PM10: 0.03 gram/bhp/hr
- SO_2: low-sulfur diesel fuel, combustion controls, restricted operating hours

Emergency Firewater Pump Engine, 556 hp (Tier 4 engine)

- NOx: 1.5 gram/bhp/hr
- CO: 2.6 gram/bhp/hr
- VOC: 0.14 gram/bhp/hr
- PM10: 0.015 gram/bhp/hr
- SO_2: low-sulfur diesel fuel, combustion controls, restricted operating hours

Sulfur Recovery Unit

- Good combustion practice, gaseous fuel only, thermal oxidizer and caustic scrubber
- NOx: 4.8 lb/hr, 24-hour average
- CO: 4.0 lb/hr, 1-hour average
- VOC: 32.84 lb/hr, annual average
- PM10: 0.16 lb/hr, 24-hour average
- SO_2: 2.02 lb/hr, 3-hour average

CO_2 Vent – No Controls

- CO: 1,000 ppmv
- VOC: 40 ppmv

Gasification and Rectisol Flares

- Good combustion practice, gaseous fuel only, natural gas flare pilot.

SRU Flare

- Good combustion practice, gaseous fuel only, natural gas flare pilot, inlet gas sulfur scrubber.

VOC Stream Components (including the pumps, valves, compressors, connectors, etc. of the methanol, propylene, H_2S-laden methanol, CO_2-laden methanol, and acid gas streams from the Gasification System, and the sulfur, tail gas treatment unit process, and tail gas treatment unit amine streams from the Sulfur Recovery System)

- Leak detection and repair (LDAR) program.

Gasifier Warming – Pipeline Quality Natural Gas

- NOx: 0.11 lb/MMBtu

- CO: 0.09 lb/MMBtu
- VOC: 0.007 lb/MMBtu
- PM10: 0.008 lb/MMBtu
- SO_2: 0.002 lb/MMBtu

Feedstock, Dust Collector

- PM10: 0.005 grain/scf outlet dust loading

Inactive Coke Storage Pile

- PM10: Emissions will be mitigated using a surface stabilizing compound.

Emission Offsets

District Rule 2201 requires that the applicant provide emission offsets, in the form of banked ERCs, for the project's stationary source emissions exceeding the SJVAPCD offset thresholds. HECA would require offsets for VOC, NOx, SO_2 and PM10 based on District Rule 2201. **Air Quality Table 22** shows the District's summary of the emission liabilities that need to be offset under Rule 2201 requirements.

Air Quality Table 22
HECA District Offset Calculations (lb/year)

Offset Need Determination	NOx	CO	VOC	SO_2	PM10
HECA Total Emissions	389,782	793,907	118,108	76,013	223,201
Offset Threshold	20,000	200,000	20,000	54,750	29,200
Offsets Triggered?	**Yes**	**No**[a]	**Yes**	**Yes**	**Yes**

Source: PDOC (SJVAPCD 2010c).
Note: [a] – The offset requirements for CO, although above the offset threshold, are exempted in attainment areas where ambient air quality standards are not violated. The project's modeling analysis provided sufficient proof to the District that CO ambient air quality standards would not be violated by this project, so CO offsets are not required.

All air pollutant offsets provided for the project, by District rule, are estimated on a quarterly basis. The applicant is proposing several sources of offsets to mitigate the project's potential emissions. Calculations of the required ERCs are based on the distance of the project from different sources of offsets. The District requires an offset ratio of 1.3:1 for major sources for off-site ERCs within 15 miles. For areas outside of 15 miles, ERCs must be provided at a ratio of 1.5:1. The applicant's ERCs are obtained from sources more than 15 miles away for all pollutants, except VOC; therefore, a distance ratio of 1.5:1 is used for District offset purposes for all pollutants, with the exception of VOC where a distance of 1.3:1 is used (SJVAPCD 2010c). The District determines appropriate interpollutant offset ratios on a case-by-case basis.

As shown in **Air Quality Table 23** through **Air Quality Table 26**, the applicant has demonstrated, per District requirements and Energy Commission policy, that it owns ERCs in quantities sufficient to offset the project's NOx, VOC, SO_2 and PM10 emissions. PM2.5 emissions are not currently offset separately from PM10 emissions, a discussion of the offset mitigation in terms of PM2.5 mitigation is discussed separately in the Chemically Reactive Pollutants Impact section.

NOx Emission Offsets

Air Quality Table 23 provides a summary of the total project NOx emissions subject to District offsets and identifies the project offset emission reduction credit sources. Credit S-3273-2 was created in November 1983 from the shutdown of a catalytic cracker, fluid coker, and CO boiler. Credits C-1058-2 and C-1059-2 were created in January 2008 through the installation of a Selective Catalytic Reduction unit, a scrubber, and a conversion from fuel oil to natural gas.

Air Quality Table 23
NOx Offsets Available for HECA

Offset Source Location	Credit Number	Total Q1 (lb)	Total Q2 (lb)	Total Q3 (lb)	Total Q4 (lb)
Emissions Above Threshold[a]	---	92,319	92,319	92,319	92,319
6500 Refinery Ave., Bakersfield	S-3273-2	120,500	120,500	120,500	120,500
11535 E. Mountain Ave., Kingsburg	C-1058-2	10,100	10,100	10,100	10,100
11535 E. Mountain Ave., Kingsburg	C-1059-2	21,900	21,900	21,900	21,900
Total ERC Holdings	---	152,500	152,500	152,500	152,500
Total HECA Offsets required @ 1.5:1	---	138,478.5	138,478.5	138,478.5	138,478.5
Surplus	---	14,021.5	14,021.5	14,021.5	14,021.5

Sources: L&W 2010L, SJVAPCD 2010a, and PDOC (SJVAPCD 2010c).
Note: [a] – The offset emission thresholds are provided in **Air Quality Table 22**, and the quarterly threshold is one quarter of the annual threshold shown in that table.

The applicant's offset proposal fully complies with the District's NOx offset requirements.

VOC Emission Offsets

Air Quality Table 24 provides a summary of the total project VOC emissions subject to District offsets and identifies the project offset emission reduction credit sources. Credits S-3305-1 and future divided credits S-3306-1, which are scheduled to be obtained by the applicant on the dates listed in the table, are all from the same emission reduction event that occurred in September 1979 through the shutdown of an entire stationary source.

Air Quality Table 24
VOC Offsets Available for HECA

Offset Source Location	Credit Number	Total Q1 (lb)	Total Q2 (lb)	Total Q3 (lb)	Total Q4 (lb)
Emissions Above Threshold[a]	---	24,474	24,474	24,474	24,474
20807 Stockdale Hwy, Bakersfield	S-3305-1	14,625	14,625	14,625	14,625
20807 Stockdale Hwy, Bakersfield (2/11)	S-3306-1	11,437.5	11,437.5	11,437.5	11,437.5
20807 Stockdale Hwy, Bakersfield (4/11)	S-3306-1	7,937.5	7,937.5	7,937.5	7,937.5
Total ERC Holdings	---	34,000	34,000	34,000	34,000
Total HECA Offsets required @ 1.3:1	---	31,816.5	31,816.5	31,816.5	31,816.5
Surplus	---	2,183.5	2,183.5	2,183.5	2,183.5

Sources: L&W 2010L, SJVAPCD 2010a, and PDOC (SJVAPCD 2010c).
Note: [a] – The offset emission thresholds are provided in **Air Quality Table 22**, and the quarterly threshold is one quarter of the annual threshold shown in that table.

The applicant's offset proposal fully complies with the District's VOC offset requirements.

SOx and PM10 Emission Offsets

The applicant has proposed the use of SOx emissions offsets to mitigate PM10 emissions as a form of interpollutant offsets to complete the PM10 offset package. **Air Quality Table 25** provides a summary of the total project SO_2 and PM10 emissions subject to District offsets and identifies the project offset emission reduction credit sources. Credit S-3275-5 was created in March of 1992 through the shutdown of a tail gas incinerator. Credits C-1058-5 and C-1059-5 were created in January 2008 through the installation of a scrubber, and a conversion from fuel oil to natural gas.

Air Quality Table 25
SOx and PM10 Offsets Available for HECA

Offset Source Location	Credit Number	Total Q1 (lb)	Total Q2 (lb)	Total Q3 (lb)	Total Q4 (lb)
SOx Emissions Above Threshold[a]	---	5,315	5,315	5,315	5,315
PM10 Emissions Above Threshold[a]	---	48,489	48,489	48,489	48,489
6451 Rosedale Hwy, Bakersfield	S-3275-5	42,000	42,000	42,000	42,000
11535 E. Mountain Ave., Kingsburg	C-1058-5	24,500	24,500	24,500	24,500
11535 E. Mountain Ave., Kingsburg	C-1059-5	70,500	70,500	70,500	70,500
Total ERC Holdings	---	137,000	137,000	137,000	137,000
Total HECA SOx Offsets required @ 1.5:1	---	7,972	7,972	7,972	7,972
Total HECA PM10 Offsets required @ 1.5:1	---	72,733	72,733	72,733	72,733
Total HECA Offsets required	---	80,705	80,705	80,705	80,705
Surplus	---	56,295	56,295	56,295	56,295

Sources: L&W 2010L, SJVAPCD 2010a, and PDOC (SJVAPCD 2010c).
Note: [a] – The offset emission thresholds are provided in **Air Quality Table 22**, and the quarterly threshold is one quarter of the annual threshold shown in that table.

The applicant's offset proposal fully complies with the District's SOx and PM10 offset requirements.

The applicant has proposed the use of SOx for PM10 interpollutant offsets. SOx is accepted as one of the major precursors of PM10 and PM2.5 through reaction with ammonia to form ammonium sulfates. Reductions in SOx, particularly in areas that are ammonia rich such as the SJVAB, will reduce secondary particulate formation. Therefore, interpollutant offsets of SOx for PM10 can be used to reach the goal of mitigating a project's impacts to regional ambient particulate concentrations. The key issue is the determination of an appropriate interpollutant offset ratio, which depends on the existing levels of PM precursors and the general air chemistry of the area in question. The District has determined that an offset ratio of 1:1 is adequate for SOx for PM10 interpollutant ERC trading. Staff has provided a comment to the District regarding the appropriateness of this offset ratio and the Final Staff Assessment (FSA) will provide additional information based on the comment response provided by the District in the FDOC.

CEQA Offsets

Energy Commission staff have long held that for fossil fuel power plants, the annual operation emissions for all nonattainment pollutants and their precursors need to be offset at a minimum 1:1 ratio. For this project, as shown in **Air Quality Table 26**, the District's offset requirements would exceed that minimum offsetting goal for NOx, VOC, SO_2, and PM10.

Air Quality Table 26
Total Operations Offset Ratio for HECA's SJVAB Emissions

Pollutant	Annual Emissions	District Required ERCs	Offset Ratio
NOx	203.3 tons/year	277.0 tons/year	1.36:1
VOC	60.2 tons/year	63.6 lbs/year	1.06:1
SOx + PM10	150.4 tons/year	161.4 tons/year[a]	1.07:1

Source: Compilation of data from **Air Quality Tables 17**, and **23** through **25**
Note: [a] – SO_2 ERCs.

Staff notes that with the assumption that an interpollutant offset ratio of SOx for PM10[17] of 1:1 the applicant's offset proposal would meet staff's CEQA threshold of a minimum offset threshold of 1:1 for all non-attainment pollutants and their precursors.

Voluntary Air Quality Improvement Agreement

The applicant has entered into a voluntary Air Quality Improvement Agreement with the district to fund air quality improvements within Kern County. The funding includes an initial fee of over $680,000 and a potential additional fee depending on whether the district's target NOx emission level is met during a two year demonstration period that starts with commercial operation. This agreement specifies that the initial fee will be paid at the time of commercial operation, unless waived by HECA, and that the additional fee, if necessary, will be paid within 180 days after the completion of the demonstration period. The additional fee is based on an agreed calculation procedure that is not to exceed the equivalent ERC cost for NOx credits. The funds obtained by the district under this agreement are to be used to fund emission reduction projects within the San Joaquin Valley Air Basin, preferentially in Kern County, that will focus on

[17] Staff evaluation of CEQA mitigation for PM2.5 impacts is the same as for PM10.

replacing older high emitting agricultural equipment in order to provide quantifiable air quality benefits within Kern County.

Staff does not consider this voluntary agreement to be necessary CEQA mitigation, as the project does not require this additional mitigation to reduce project impacts to less than significant. However, staff recognizes the additional air quality benefits that this voluntary agreement can provide and supports the applicant and district in their efforts to provide these additional air quality benefits to the region.

Adequacy of Proposed Mitigation

Staff concurs with the District's determination that the project's proposed emission controls/emission levels for criteria pollutants meets BACT requirements and that the proposed emission levels are reduced to the lowest technically feasible levels.

Staff has made a preliminary determination that the applicant's offset proposal meets both District requirements and CEQA mitigation requirements. However, there are two issues that need to be resolved prior to the issuance of the Final Staff Assessment (FSA) in order for staff to finalize this determination. These two issues are as follows:

1) SO_2-for-PM10 offset ratio.

Staff is still evaluating the appropriateness of the 1:1 offset ratio for interpollutant trading of SO_2 for PM10 in terms of providing adequate and SIP-required mitigation for the project's potential PM10 impacts and adequate mitigation for the project's PM2.5 impacts. Staff and U.S. EPA have provided comments regarding this issue to the District in our respective PDOC comment letters (CEC 2010q, U.S. EPA 2010c), and staff will be evaluating the District's response as part of our final conclusion regarding this issue.

2) PM2.5 annual emissions vs. Federal NSR Trigger

The Federal NSR offset trigger for PM2.5 emissions is 100 tons per year. District NSR regulations do not currently include requirements for PM2.5, so the Federal NSR rule applies by default. Staff and U.S. EPA both have issues regarding the emission estimate for PM2.5, which depending on the assumptions used for the cooling tower emissions could exceed 100 tons/year and require federally enforceable PM2.5 offsets. Staff and U.S. EPA have provided comments regarding this issue to the District in our respective PDOC comment letters, and staff will be evaluating the District's response as part of our final conclusion regarding this issue.

Staff's preliminary acceptance of this offset package was determined solely based on the merits of this case, including the District offset requirements, the project's emission limits, the specific ERCs proposed, and ambient air quality considerations of the region, and does not in any way provide a precedence or obligation for the acceptance of offset proposals for any other current or future licensing cases.

Staff Proposed Mitigation

Staff is proposing a condition of certification (**AQ-SC7**) to reduce the potential maintenance and on-site fuel handling emissions by requiring that the applicant obtain the latest model year and California compliant equipment for their dedicated on-road and off-road equipment fleet. Staff is also proposing a condition of certification (**AQ-SC9**) to mitigate the fugitive dust emissions potential of the on-site inactive coke storage pile[18].

Staff is also proposing conditions of certification (**AQ-SC6** and **AQ-SC8)** that would ensure that the license is amended as necessary to incorporate changes to the air quality permits and ensure ongoing compliance through the requirement of quarterly operations reports that demonstrate compliance, respectively.

Staff has considered the minority population surrounding the site (see Socioeconomics Figure 1). Since the project's direct air quality impacts have been reduced to less than significant, there is no environmental justice issue for air quality.

Chemically Reactive Pollutant Impacts

The project's gaseous emissions of NOx, SO_2, VOC and ammonia can contribute to the formation of secondary pollutants: ozone and PM10/PM2.5.

Ozone Impacts

There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the modeling to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, it can be said that the emissions of NOx and VOC from the HECA project do have the potential (if left unmitigated) to contribute to higher ozone levels in the region. These impacts would be cumulatively significant because they would contribute to ongoing violations of the state and federal ozone ambient air quality standards. Staff is recommending condition **AQ-SC5** to reduce the NOx and VOC emissions from off-road equipment during construction. The District rules require that the NOx and VOC emissions for the HECA project be offset at a greater than 1:1 ratio (provided in District conditions **AQ-2**, **AQ-5**, and **AQ-6**). Staff concludes that with these mitigation measures the project's ozone impacts are less than significant.

Secondary PM10/PM2.5 Impacts

Secondary PM10 formation, which is assumed to be 100 percent PM2.5, is the process of conversion from gaseous reactants to particulate products. The process of gas-to-particulate conversion, which occurs downwind from the point of emission, is complex and depends on many factors, including local humidity and the presence of air pollutants. The basic process assumes that the SOx and NOx emissions are converted into sulfuric acid and nitric acid first, and then react with ambient ammonia to form sulfate and nitrate. The sulfuric acid reacts with ammonia much faster than nitric acid and converts completely and irreversibly to particulate form. Nitric acid reacts with ammonia to form both a particulate and a gas phase of ammonium nitrate. The particulate phase will tend to fall out. However the gas phase can revert back to

[18] Staff believes that this staff condition will likely be replaced by District conditions when the FDOC is finalized.

ammonia and nitric acid. Thus, under the right conditions, ammonium nitrate and nitric acid establish a balance of concentrations in the ambient air. There are two conditions that are of interest, described as “ammonia rich” and “ammonia poor.” The term “ammonia rich” indicates that there is more than enough ammonia to react with all the sulfuric acid and to establish a balance of nitric acid-ammonium nitrate. Further ammonia emissions in this case will not necessarily lead to proportional increases in ambient PM2.5 concentrations. In the case of an “ammonia poor” environment, there is an insufficient amount of ammonia to establish a balance and thus additional ammonia would tend to increase PM2.5 concentrations.

The San Joaquin Valley has been the subject of an extensive secondary particulate formation study, the California Regional Particulate Air Quality Study, which has determined that the San Joaquin Valley is ammonia rich. Therefore, the ammonia emissions from the HECA project are not expected to lead to substantial further formation of ammonium nitrate or sulfate. While there will certainly be some conversion from the ammonia emitted from the HECA project, there is currently no regulatory model that can predict the conversion rate. However, because of the known relationship of NOx and SOx emissions to PM2.5 formation, it can be said that the emissions of NOx and SOx from the HECA project do have the potential (if left unmitigated) to contribute to higher PM2.5 levels in the region.

The applicant is proposing to mitigate the project’s NOx, VOC, SO_2, and PM10 emissions through the use of emission offsets and limit the ammonia slip emissions to 5 ppm. The NOx, VOC, SO_2, and PM10 offsets are proposed by the applicant to be provided for emissions above the district offset thresholds at a minimum 1.3 to 1 ratio for VOC, and 1.5 to 1 ratio for the other three pollutants. With the proposed emission offsets, staff concludes that the project would not cause significant secondary PM2.5 pollutant impacts.

CUMULATIVE IMPACTS

“Cumulative impacts” are defined as “two or more individual effects which, when considered together, are considerable or…compound or increase other environmental impacts.” (CEQA Guidelines, § 15355.) A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts.” (CEQA Guidelines, § 15130(a)(1).) Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This analysis is concerned with criteria air pollutants. Such pollutants have impacts that are usually (though not always) cumulative by nature. Rarely would a project by itself cause a violation of a federal or state criteria pollutant standard. However, a new source of pollution may contribute to violations of criteria pollutant standards because of the existing background sources or foreseeable future projects. Air districts attempt to attain the criteria pollutant standards by adopting attainment plans, which comprise a multi-faceted programmatic approach to such attainment. Depending on the air district, these plans typically include requirements for air offsets and the use of Best Available Control

Technology (BACT) for new sources of emissions, and restrictions of emissions from existing sources of air pollution.

Thus, much of the preceding discussion is concerned with cumulative impacts. The "Existing Ambient Air Quality" section describes the air quality background in the San Joaquin Valley Air Basin, including a discussion of historic ambient levels for each of the significant criteria pollutants. The "Construction Impacts and Mitigation" subsection discusses the project's contribution to the local existing background caused by project construction. The "Operation Impacts and Mitigation" section discusses the proposed project's contribution to the local existing background caused by project operation. The following subsection includes these additional analyses:

- a summary of projections for criteria pollutants by the air district and the air district's programmatic efforts to abate such pollution;
- an analysis of the proposed project's *localized cumulative impacts*, the proposed project's direct operating emissions combined with other local major emission sources; and
- an analysis of the Occidental Petroleum's EOR project, which is a HECA project-related action.

Summary of Projections

The SJVAPCD is the lead agency for managing air quality and coordinating planning efforts for the portion of Kern County within the SJVAB, so that the ozone and PM10 standards are attained in a timely fashion and attainment with CO standards are maintained[19]. The district is responsible for developing those portions of the State Implementation Plan (SIP) and the Air Quality Management Plan (AQMP), that deal with certain stationary and area source controls and, in cooperation with the transportation planning agencies (TPAs), the development of transportation control measures (TCMs). In this role the SJVAPCD is the agency with principal responsibility for analyzing and addressing cumulative air quality impacts, including the impacts of ambient ozone and particulate matter. The district has summarized the cumulative impacts of ozone and particulate matter on the air basin from the broad variety of its sources. Analyses of these cumulative impacts, as well as the measures the district proposes to reduce impacts to air quality and public health, are summarized in four publicly available documents that the district has adopted. These adopted air quality plans are summarized below.

- **Draft 2007 Ozone Plan** (8-hour ozone plan)
  Link: http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Draft_Ozone2007.htm
- **Extreme Ozone Attainment Demonstration Plan** (1-hour ozone plan)
  Link: http://www.valleyair.org/Air_Quality_Plans/AQ_plans_Ozone_Final.htm
- **2007 PM10 Maintenance Plan**
  Link: http://www.arb.ca.gov/planning/sip/sjvpm07/sjvpm07.htm
- **2008 PM2.5 Plan**

[19] The project area is in a CO attainment area that is not a maintenance area, so the SJVAPCD CO Maintenance Plan is not applicable to the project area and CO planning will not be discussed further.

Link:http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm

The Extreme Ozone Attainment Demonstration Plan for 1-hour ozone was approved by the U.S. EPA on March 8, 2010. The 2007 Ozone Plan for 8-hour ozone was adopted by the District on April 30, 2010 and by the ARB on June 14, 2007. While the U.S. EPA has not yet approved the 8-hour ozone plan they did approve a redesignation from severe to extreme 8-hour ozone nonattainment as requested in this plan. The Extreme Ozone Attainment Demonstration Plan is currently the approved ozone plan for the district/air basin, even though it covers the revoked 1-hour standard, until the 8-hour plan is approved.

The 2007 PM10 Maintenance Plan was approved and the SJVAB was redesignated as attainment by U.S. EPA on September 2008. The 2008 PM2.5 Plan was adopted by the District on April 30, 2008 and was submitted to the U.S. EPA by ARB on June 30, 2008.

Ozone

Extreme Ozone Attainment Demonstration Plan and 2007 Ozone Plan

The 2007 Ozone Plan, like the 1-hour Extreme Ozone Plan requested that the SJVAB be reclassified as an extreme nonattainment area, which was granted by U.S. EPA. The extreme designation will change permitting requirements and definitions; including lowering the emissions threshold for determining whether or not a proposed facility is a major source and increasing the minimum offset ratio to 1.5 to 1 assuming that the district cannot prove all major sources have implemented BACT, a requirement that has been added to Rule 2201.[20] Other requirements include the expeditious implementation of Reasonably Available Control Technology (RACT). The plan includes a number of control measures to implement the reductions needed for attainment, that include stationary source control measures, as well as incentive measures, innovative measures, and the implementation of other transportation and engine standard measures from the State and Federal governments. These plans targets NOx and VOC emission reductions from a multitude of stationary source types, such as wineries, feedlots, small combustion sources, gas turbines, IC engines, and various solvent/coating sources. However, the plan would not impact the HECA emission sources that already need to meet BACT.

Compliance with Ozone Plans

The SJVAPCD rules and regulations specify performance standards, offset requirements, and emission control requirements for stationary sources. The regulations also include requirements for obtaining Authority to Construct (ATC) permits and subsequent operating permits. These regulations apply to HECA and all other projects with emission sources. In general, triennial updates of the attainment plans ensure that population, employment, and transportation trends in the region are taken into account, and compliance with SJVAPCD rules and regulations ensures consistency with the regional air quality management plans.

[20] However, this Rule 2201 requirement, as provided in Section 4.8.1, does not apply to HECA as the permit application was deemed complete before this rule update became effective.

Energy Commission staff has evaluated a potential concern that the HECA project could interfere with the attainment effort of the 2007 Ozone Plan if it relies on offsets created by emission reductions prior to the plan baseline. The SJVAPCD is expecting new stationary sources like HECA to use pre-baseline credits (pre-2002 for the 2007 Ozone Plan) to allow growth from permitted stationary sources during the period of this plan, but as a safeguard, a cap would be established on the quantity of pre-baseline credits used by new sources. Additionally, the integrity of the proposed mitigation may be adversely affected by the annual equivalency demonstration required by SJVAPCD Rule 2201, Section 7, which ensures that the district's offset requirements are at least as stringent as the federal requirements. Since the project FDOC is expected to be issued before there is any failure in the equivalency demonstration, the ERCs used for HECA need not be "surplus at time of use". The implication is that the ERCs surrendered for HECA are presently surplus and they would not be subject to discounting to demonstrate equivalency with federal offset requirements. The project could result in future failures in the annual NSR offset equivalency demonstration, which would impact how future project ERC sources are evaluated, but that would not directly impact the offset compliance status for the HECA project. Therefore, because the project would use BACT to control ozone precursor emissions and ERCs at a minimum offset ratio of 1.5 to 1 (NOx) and 1.3 to 1 (VOC) to fully offset ozone precursors as required by the effective version of New Source Review Rule 2201 at the time of the project's application being deemed complete, staff has determined that the project would not directly conflict with the district's 2007 Ozone Plan or regional ozone attainment goals.

Particulate Matter

2007 PM10 Maintenance Plan

The 2007 PM10 Maintenance Plan illustrates how the SJVAPCD intends to continue the efforts of the 2003 PM10 Plan and 2006 PM10 Plan that implemented aggressive PM10 controls in the region, including Reasonably Available Control Measures (RACM) for large existing sources of PM10 and fugitive dust. The 2007 PM10 Maintenance Plan includes a request for reclassification to "attainment" for the federal PM10 standard, and it provides for continued attainment for 10 years from the designation. In November 2008, the U.S. EPA redesignated the SJVAPCD to attainment for the federal PM10 standard (73 FR 66759, November 12, 2008).

2008 PM2.5 Plan

The District prepared a 2008 PM2.5 Plan which focuses primarily on the strategy to attain the 1997 annual standard set by the U.S. EPA. In 2006, U.S. EPA revised the 24-hour standard to a lower level, and the attainment plans for the new standard may be required by 2012 or 2013. While the U.S. EPA prepares additional rules for attainment plans, the measures in 2008 PM2.5 Plan will also provide for progress towards the more stringent 2006 PM2.5 standards and the State standard for PM2.5.

The 2008 PM2.5 Plan contains a comprehensive list of strict regulatory and incentive-based measure to reduce directly emitted PM2.5 and precursor emissions throughout the Valley. The plan considers all of the following four facets of control strategy:

- Regulatory Control Measures for Stationary Sources,

- Incentive-based Strategies,
- Innovative Strategies and Programs, and
- Local, State, and Federal Sources/Partnerships

Compliance with Particulate Plans

Energy Commission staff is concerned that the HECA project could interfere with the attainment effort of the 2008 PM2.5 Plan if it relies on SOx emission reduction credits without an adequate interpollutant trading ratio for PM2.5 increases. The "reasonable further progress" calculations in the 2008 PM2.5 Plan shows that about ten times more tons of direct PM2.5 need to be reduced than SO_2 (Table 8-2 of 2008 PM2.5 Plan). The 2014 Receptor Modeling Documentation supporting the 2008 PM2.5 Plan indicates that reducing SOx would not be as effective as reducing direct PM2.5 or NOx. The district inventory of SOx is too small to have enough of an impact when compared to direct PM2.5 or NOx. Interpollutant trading is allowed with "the appropriate scientific demonstration of an adequate trading ratio" (Rule 2201, Section 4.13), and the SJVAPCD 2007 PM10 Maintenance Plan (see Appendix E of the Maintenance Plan) indicates that the minimum ratio would be one-to-one with higher interpollutant ratios if appropriate under Rule 2201. The FDOC indicates that the approved interpollutant offset ratio for SOx for PM10 for the HECA project is 1 to 1. However, staff notes that although implementation of trading under District Rule 2201 is subject to federal oversight, there is no evidence in the record indicating whether the methods used by the district in developing the interpollutant SOx for PM10 ratio has been specifically reviewed and/or approved by U.S. Environmental Protection Agency.

Additionally, there are issues regarding the PM2.5 emission estimate for the project that have been commented on by Energy Commission staff in our PDOC comment letter (CEC 2010q) and by U.S. EPA in their PDOC comment letter (U.S. EPA 2010c). Staff believes that the PM2.5 emissions, with the current operations assumptions would exceed the Clean Air Act New Source Review trigger of 100 tons per year, and U.S. EPA notes in their PDOC comment letter that PM2.5 offsets, if interpollutant offsets are used, must "…comply with an interprecursor trading hierarchy and ratio approved by the Administrator". Additionally, U.S. EPA indicates that their modeling efforts indicate that an interpollutant trading ratio of greater than 1 to 1 would be necessary for SOx for PM2.5 offsets.

Although there is no formal federal endorsement of the District's interpollutant trading approach for PM10 and there are questions whether PM2.5 offsets are necessary, Energy Commission staff preliminarily concludes that the HECA project would not conflict with regional particulate matter attainment and maintenance goals due the following reasons and assumptions:

- The district and the applicant will provide staff formal documentation that PM2.5 emissions are less than 100 tons/year, through the requirement of revised enforceable emission limits or other means.
- The project is required to apply a distance ratio to the emission reduction credits that increases the overall offset ratio to 1.5 to 1.

- Staff recognizes that the PM2.5 attainment plan has been previously adopted by ARB, and the SJVAPCD has determined that the interpollutant trading ratio for HECA is appropriate.
- The FDOC shows that HECA project is likely to comply with the particulate matter plans by meeting its permit requirements and complying with the existing applicable rules and regulations.

Staff may revise this preliminary conclusion: 1) if the enforceable PM2.5 emissions limit cannot be demonstrated to staff's satisfaction to be below 100 tons/year; or 2) if the U.S. EPA provides persuasive information that the one-to-one SO_2 for PM10 offset ratio would significantly interfere with the attainment effort of the 2008 PM2.5 Plan.

Localized Cumulative Impacts

Since the power plant air quality impacts can be reasonably estimated through air dispersion modeling (see the "Operation Modeling Analysis" subsection) the proposed project's contributions to localized cumulative impacts can be estimated. To represent *past* and, to an extent, *present projects* that contribute to ambient air quality conditions, the Energy Commission staff recommends the use of ambient air quality monitoring data (see the "Existing Ambient Air Quality" subsection), referred to as the *background*. The staff takes the following steps to estimate what are additional appropriate "present projects" that are not represented in the background and "reasonably foreseeable projects":

- First, the Energy Commission staff (or the applicant) works with the air district to identify all projects that have submitted, within the last year of monitoring data, new applications for an authority to construct (ATC) or permit to operate (PTO) and applications to modify an existing PTO within 6 miles of the project site. Based on staff's modeling experience, beyond 6 miles there is no statistically significant concentration overlap for non-reactive pollutant concentrations between two stationary emission sources.
- Second, the Energy Commission staff (or the applicant) works with the air district and local counties to identify any new area sources within 6 miles of the project site. As opposed to point sources, area sources include sources like agricultural fields, residential developments or other such sources that do not have a distinct point of emission. New area sources are typically identified through draft or final Environmental Impact Reports (EIRs) that are prepared for those sources. The initiation of the EIR process is a reasonable basis on which to determine what is "reasonably foreseeable" for new area sources.
- The data submitted, or generated from the applications with the air district for point sources or initiating the EIR process for area sources, provides enough information to include these new emission sources in air dispersion modeling. Thus, the next step is to review the available EIR(s) and permit application(s), determine what sources must be modeled and how they must be modeled.
- Sources that are not new, but may not be represented in ambient air quality monitoring are also identified and included in the analysis. These sources include existing sources that are co-located with or adjacent to the proposed source (such as an existing power plant). In most cases, the ambient air quality measurements

are not recorded close to the proposed project, thus a local major source might not be well represented by the background air monitoring. When these sources are included, it is typically a result of there being an existing source on the project site and the ambient air quality monitoring station being more than 2 miles away.

- The modeling results must be carefully interpreted so that they are not skewed towards a single source, in high impact areas near that source's fence line. It is not truly a cumulative impact of HECA if the high impact area is the result of high fence line concentrations from another stationary source and HECA is not providing a substantial contribution to the determined high impact area.

Once the modeling results are interpreted, they are added to the background ambient air quality monitoring data and thus the modeling portion of the cumulative assessment is complete. Due to the use of air dispersion modeling programs in staff's cumulative impacts analysis, the applicant must submit a modeling protocol, based on information requirements for an application, prior to beginning the investigation of the sources to be modeled in the cumulative analysis. The modeling protocol is typically reviewed, commented on, and eventually approved in the Data Adequacy phase of the licensing procedure. Staff typically assists the applicant in finding sources (as described above), characterizing those sources and interpreting the results of the modeling. However, the actual modeling runs are usually left to the applicant to complete. There are several reasons for this; modeling analyses take time to perform and require significant expertise, the applicant has already performed a modeling analysis of the proposed project alone (see the "Operation Modeling Analysis" subsection), and the applicant can act on its own to reduce stipulated emission rates and/or increase emission control requirements as the results warrant. Once the cumulative project emission impacts are determined, the necessity to mitigate the proposed project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or the applicant (see the "Operation Mitigation" subsection).

The list of possible new stationary sources within six miles of the project site from the SJVAPCD included seven sources (URS 2010a). However, no significant stationary sources with greater than 5 tons of permitted emissions of any were identified within six miles of the project site. Therefore, it has been determined that no stationary sources requiring a cumulative modeling analysis exist within a 6-mile radius of the project site.

However, there is the potential for additional projects, such as renewable energy projects or oil and gas recovery projects in the general area of the proposed project site. Additionally, there is the potential for significant additional development within the air basin. The corresponding potential for an increase air basin emission sources is a major part of staff's rationale for recommending Conditions of Certification **AQ-SC7** that is designed to mitigate the proposed project's cumulative impacts by reducing the dedicated on-site vehicle emissions during site operation. With this recommended mitigation measure, staff has concluded that the cumulative air quality impacts are less than significant.

Staff has considered the minority population surrounding the site (see **Socioeconomics Figure 1**). Since the proposed project's cumulative air quality impacts have been mitigated to less than significant, there is no environmental justice issue for air quality.

Project-Related Actions - Occidental Petroleum EOR Project

This section examines the potential air quality impacts of the Occidental Petroleum (Enhanced Oil Recovery) EOR project that will use the HECA project's CO_2 for tertiary oil recovery. The EOR project includes the construction of the CO_2 pipeline, the drilling of CO_2 injection wells, the construction of the CO_2 injection and the CO_2 recovery and recycling systems. This HECA related project will be subject to the completion of a separate EIR/EIS, and will be required to mitigate emissions as determined to be required under CEQA and NEPA.

The air quality impacts of this related project will include short-term construction impacts that will occur during the same timeframe as the HECA project construction; and operating impacts related to this EOR project will include stationary source emissions from the new oil recovery and CO_2 recycling systems and indirect emissions from the additional electrical energy needed for the CO_2 compressors and other electrical requirements to operate the EOR system. However, if CO_2 were not being made available from the HECA project then it is likely that Occidental would use other tertiary oil recovery methods, such as water or other gas injection, that could have operating emissions as high as or higher than the proposed CO_2 based EOR system.

Staff initial findings regarding this Project-Related Action are as follow:

- The construction related impacts of this EOR project will generally occur miles from the HECA project, and construction emissions mitigation will be required as part of that project's CEQA/NEPA process. Staff believes that with adequate mitigation the cumulative construction impacts of HECA and the EOR project will be less than significant.
- The direct operating stationary source emissions of the EOR project will require appropriate permitting from the SJVAPCD, with emission reduction mitigation as required under District Rules (such as BACT and offsets, if necessary). Therefore, staff believes that the cumulative operation impacts of HECA and the EOR project will be less than significant.

In addition, staff makes the following inter-agency request to ensure that the cumulative air quality impacts of these two projects are less than significant:

- The Energy Commission requests that the EOR project CEQA/NEPA responsible agencies (expected to be the California Department of Conservation's Division of Oil, Gas and Geothermal Resources) require construction emission mitigation measures that are as strict as or stricter than those measures provided in Staff Conditions **AQ-SC3** through **AQ-SC5**.

Occidental has not yet provided emission estimates for the construction and operation of the EOR system. These emission estimates and other details of the EOR project's EIR/EIS process, to the extent available, will be provided for informational purposes in the FSA.

COMPLIANCE WITH LORS

The San Joaquin Valley Air Pollution Control District issued a Preliminary Determination of Compliance (PDOC) for the Hydrogen Energy California project on June 21, 2010 (SJVAPCD 2010c). The District will issue a Final Determination of Compliance (FDOC) after resolving issues raised by the public and agency comments. Compliance with all District Rules and Regulations was demonstrated to the district's satisfaction in the PDOC. The district's PDOC conditions are presented in the Conditions of Certification (**AQ-1** to **AQ-292**).

Staff submitted an official PDOC comment letter on August 3, 2010 (CEC 2010q) and expects that the FDOC will contain revisions to conditions due to Energy Commission, applicant, or third party comments, and staff will provide the revised FDOC findings or conditions of certification in the Final Staff Assessment (FSA).

FEDERAL

The district is responsible for issuing the federal New Source Review (NSR) permit and has been delegated enforcement of the applicable New Source Performance Standards (Subparts Db, Y, KKKK, and IIII). U.S. EPA is in the process of completing the project's Prevention of Significant Deterioration (PSD) permit for the project, applied for by the applicant in June 2009 (HEI 2009e) and amended in October 2009 (HEI 2009g), which is necessary before the project can initiate construction.

U.S. EPA provided comments on the district's PDOC on August 16^{th} (U.S. EPA 2010c), and may provide comments on this Staff Assessment. The U.S. EPA PDOC comments of concern regard the emissions estimates and regulatory triggers for PM2.5 and Hazardous Air Pollutants. Staff provided similar comments regarding PM2.5 and will be following the district's response to the U.S. EPA comments closely. Additionally, staff will evaluate any comments received from U.S. EPA on the PSA and address them, if necessary, in the FSA.

STATE

The applicant will demonstrate that the project will comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury, with the issuance of the district's Preliminary Determination of Compliance and the Energy Commission's affirmative finding for the project.

The district's conditions and staff verifications will ensure compliance with the emission limit requirements of the ARB diesel engine ATCMs and the applicant will also be required to comply with the idle restriction requirements of the ATCMs. The applicant is exempt from the requirements of the Air Toxics "Hot Spots" risk assessment requirements because the project had a risk assessment performed as part of its district permitting and that the risk assessment found that the project's emissions would result in less than significant health risks to the public.

LOCAL

As part of the Energy Commission's licensing process, in lieu of issuing a construction permit to the applicant for the HECA project, the district will prepare and present to the

Commission a DOC, both a PDOC, and after a public comment period, an FDOC. The PDOC was published on June 21, 2010 (SJVAPCD 2010c), and the FDOC will be published after the district has had time to respond to comments received on the PDOC, including comments from the applicant, the Energy Commission, and other interested parties such as U.S. EPA.

The district rules and regulations specify the emissions control and offset requirements for new sources such as the HECA project. Best Available Control Technology (BACT) will be implemented, and emission reduction credits (ERCs), proposed by the Applicant and approved and certified by the district, will fully mitigate project nonattainment pollutant (including precursors) emissions so that they would be consistent with the strategies and future emissions anticipated under the district's air quality attainment and maintenance plans.

The district's PDOC states that the proposed project is expected to comply with all applicable District rules and regulations. The DOC evaluates whether and under what conditions the proposed project will comply with the district's applicable rules and regulations, as described below.

Rule 1080 – Stack Monitoring

This rule grants the Air Pollution Control Officer (APCO) the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for record keeping, reporting, and notification. The PDOC includes conditions to assure compliance with this rule.

Rule 1081 – Source Sampling

This rule requires adequate and safe facilities for use in sampling to determine compliance with emission limits, and specifies methods and procedures for source testing and sample collection. The PDOC includes conditions to assure compliance with this rule.

Rule 1100 – Equipment Breakdown

This rule defines a breakdown condition, the procedures to follow if one occurs, and the requirements for corrective action, issuance of an emergency variance, and reporting. This rule is applied to the owner of any source operation with air pollution control equipment, or related operating equipment that controls air emissions, or continuous monitoring equipment. The PDOC includes conditions to assure compliance with this rule.

Rule 2010 – Permits Required

This rule requires any person who is building, altering, replacing or operating any source that emits, may emit air contaminants, or may reduce emissions, to first obtain authorization from the district in the form of an Authority to Construct or a Permit to Operate. Filing an application with the district (HEI 2009d) and obtaining the ATC will fulfill the requirements of this rule.

Rule 2201 – New and Modified Stationary Source Review Rule

The main function of the district's New Source Review Rule is to allow for the issuance of Authorities to Construct, Permits to Operate, the application of Best Available Control Technology (BACT) to new or modified permit source and to require the new permit source to secure emission offsets.

Section 4.1 – Best Available Control Technology

Best Available Control Technology (BACT) is defined as the most stringent emission limitation or control technique of the following: a) achieved in practice for a category and class of source; b) contained in any State Implementation Plan and has been approved by the U.S. EPA for a category and class of source; c) contained in an applicable federal New Source Performance Standard; or d) any other emission limitation or control technique that the district's Air Pollution Control Officer (APCO) finds is technologically feasible and cost effective. BACT is required for any new or modified emission unit that results in an emissions increase of 2.0 lb/day. However, Section 4.2.1 states that BACT is not required for CO emissions from any new or modified emissions unit if those sources emit less than 200,000 lb/year of CO. In the case of HECA, BACT applies for the following equipment and pollutants:

- Gas Turbine/HRSG – NOx, CO, VOC, SOx, PM10
- Feedstock Handling and Storage System – PM10
- Gasifier Refractory Heaters – NOx, CO, VOC, SOx, PM10
- Gasification Flare – NOx, CO, SOx
- Sulfur Recovery Unit Flare – NOx, CO, SOx, PM10
- Three Cooling Towers – PM10
- Sulfur Recovery System – SOx
- CO2 Recovery and Vent System – VOC, CO
- Auxiliary Boiler – NOx, CO, VOC, SOx, PM10
- Emergency Generator Engines and Firewater Pump – NOx, CO, VOC, SOx

The district has determined that the control equipment or basic equipment proposed currently meets the requirements of BACT, with the exception of the gas turbine/HRSG NOx, VOC, and CO emissions where the district is granting BACT emission concentration flexibility due to the lack of proven BACT emission limits for gas turbines operating with this fuel source and its required gas turbine combustor system (SJVAPCD 2010c). The district has established target emission rates below the applicant's proposed emission rates for the gas turbine/HRSG and is allowing the applicant 24 months of operation to establish/demonstrate the lowest achievable emission rates which will be used by the district to make a final BACT determination. The applicant's proposed and district's target gas turbine/HRSG BACT emission concentration limits during normal operations (at 15% O_2) are as follows:

Air Quality Table 27
Applicant Proposed and District Target Gas Turbine/HRSG BACT Emission Rates

Pollutant	Applicant BACT Proposal	District BACT Target
NOx	4.0 ppmvd	2.0 ppmvd 2.5 ppmvd (1-hour avg.)
VOC	1.0 ppmvd (hydrogen-rich fuel) 2.0 ppmvd (natural gas)	1.0 ppmvd (hydrogen-rich fuel) 1.5 ppmvd (natural gas)
CO	3.0 ppmvd (hydrogen-rich fuel) 5.0 ppmvd (natural gas)	3.0 ppmvd (hydrogen-rich fuel) 4.0 ppmvd (natural gas)

Note: District BACT Targets are 3-hour rolling averages unless otherwise specified.

The PDOC includes conditions to assure compliance with the BACT determinations, including the gas turbine/HRSG BACT demonstration requirements.

Section 4.5 through 4.13 – Emission Offset Requirements

Section 4.5 specifies that emissions offsets for new or modified sources are required when their emissions are equal to or exceed the following levels:

- Oxides of Nitrogen, NOx – 20,000 lbs/year;
- Volatile Organic Compounds, VOC – 20,000 lbs/year;
- Carbon Monoxide, CO – 200,000 lbs/year;
- PM10 – 29,200 lbs/year;
- Sulfur Oxides, SOx – 54,750 lbs/year.

If constructed, the HECA project would exceed the above emission levels for NOx, VOC, CO, PM10 and SOx based on the permitted equipment emission limits and the applicant's requested facility operation of 8,322 hours per year.

Section 4.6 specifies that emissions offsets are not required for increases of CO in attainment areas, if the applicant demonstrates that the emissions increase will not cause or contribute to a violation of the ambient air quality standards, and that those emissions are consistent with Reasonable Further Progress. The district has evaluated the project's CO emissions and has concluded that they are consistent with Reasonable Further Progress and do not require offsets.

Section 4.8[21] specifies that the emission offsets provided shall be adjusted according to the distance of the offset from the project proposed site. The ratios are:

- Internal or on-site source – 1 to 1;
- Within 15 miles of the source – 1.2 to 1 (non-major source), 1.3 to 1 (major source); and
- 15 miles or more from the source – 1.5 to 1.

Section 4.13.1 specifies that major sources (defined as those sources that emit greater than 25 tons of NOx and VOC, 100 tons CO, or 70 tons of PM10 and SO_x) that are shut down and thus generate an ERC may not be used as an offset for a new major source (like HECA) unless those ERCs are included in an EPA-approved attainment plan.

Section 4.13.3 allows for the use of interpollutant offsets (including PM10 precursors for PM10) on a case-by-case basis, provided that the applicant demonstrates that the emissions increase will not cause a violation of any ambient air quality standard. The ratio for interpollutant trading shall be based on an air quality analysis and shall be equal to or greater than the minimum offsetting requirement (the distance ratios) of this rule (Section 4.8).

[21] Rule 2201 Section 4.8.1 currently requires a 1.5 to 1 offset ratio for NOx and VOC emissions; however, that part of the rule became effective after the HECA application was deemed complete by the District, so the former distance ratio requirements as listed herein apply to HECA.

Section 4.13.4 requires Actual Emissions Reductions (AER) used as offsets to have occurred during the same calendar quarter as the emissions increases being offset. Exceptions to this rule (4.13.7 through 4.13.9) allow PM emission reductions that occurred from October through March to offset PM emissions occurring anytime during the year, for NOx and VOC emission reductions that occurred from April through November to offset NOx and VOC emissions occurring anytime during the year, and for CO emission reductions that occurred from November through February to offset CO emissions occurring anytime during the year.

The district has evaluated the offset need and offsets proposed by the applicant, including evaluating the proposed interpollutant offsets. The district has found that the offset proposal will comply with these regulations (SJVAPCD 2010c).

Section 4.14 – Ambient Air Quality Standards

Section 4.14.1 requires that a new source not cause, or make worse, the violation of an ambient air quality standard as demonstrated through analysis with air dispersion models. The district completed the required modeling analysis and found that the project would comply with this regulation as the emissions would not cause new violations for the attainment pollutants and would not cause a significant increase in PM10 levels. The district's PM10 modeling determined the following comparison with U.S. EPA PM10 significance levels:

	Significance Level	Facility Impact
PM10 24-hour	5 $\mu g/m^3$	4.49 $\mu g/m^3$
PM10 Annual	1 $\mu g/m^3$	0.6 $\mu g/m^3$

Staff also reviewed the applicant's modeling analysis that indicates no new exceedances of ambient air quality standards. Compliance with this rule is expected.

Section 4.15 – Additional Requirements for new Major Sources and Federal Major Modifications

Section 4.15.2 requires that the owner of a proposed new major source or federal major modification demonstrate to the satisfaction of the district that all major stationary sources subject to emission limitations that are owned or operated by the applicant or any entity controlling or under common control with the applicant in California, are in compliance or on a schedule for compliance with all applicable emission limitations and standards. The applicant has indicated that they will provide a certification in compliance with this regulation prior to issuance of the FDOC. Compliance with this rule is expected.

Rule 2520 – Federally Mandated Operating Permits

Rule 2520 requires that a project owner file a Title V Operating Permit from the U.S. EPA with the district within 12 months of commencing operation. A project is subject to this requirement if any of the following apply: the project is a major stationary source (under PSD definitions), it has the potential to emit greater than 100 tons per year of a criteria pollutant, any equipment permitted is subject to New Source Performance Standards, the project is subject to Title IV Acid Rain program, or the owner is required to obtain a PSD Permit from the U.S. EPA. The Title V Permit application requires that the owner submit information on the operation of the air polluting equipment, the emission controls, the quantities of emissions, the monitoring of the equipment as well as other information requirements. The PDOC includes conditions to assure compliance with this rule.

Rule 2540 – Acid Rain Program

A project greater than 25 megawatts (MW) and installed after November 15, 1990, must submit an acid rain program permit application to the district. The acid rain requirements will become part of the Title V Operating Permit (Rule 2520). Monitoring of the NOx and SOx emissions and a relatively small quantity of SOx allowances (from a national SOx allowance bank) will be required as well as the use of a NOx CEM. The PDOC includes conditions to assure compliance with this rule.

Rule 4001 – New Source Performance Standards

Rule 4001 specifies that a project must meet the requirements of the Federal New Source Performance Standards (NSPS), according to Title 40, Code of Federal Regulations, Part 60, Chapter 1. The specific subparts that are applicable to the HECA project include:

- Subpart Db - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
- Subpart Y - Standards of Performance for Coal Preparation and Processing Plants
- Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
- Subpart KKKK - Standards of Performance for Stationary Combustion Turbines

Subpart Db is applicable to the auxiliary boiler and includes exhaust monitoring and recordkeeping requirements. The PDOC includes conditions to assure compliance with this rule.

Subpart Y is applicable to the feedstock handling equipment and includes emission control performance, monitoring, and recordkeeping requirements. The PDOC includes conditions to assure compliance with this rule.

Subpart KKKK, that overrides subpart GG, which pertains to Stationary Gas Turbines, requires that a project meets specific NOx and SO_2 standards, meets continuous emission monitoring system requirements, meets various emission and fuel reporting requirements, and meets specified NOx and SOx performance testing requirements. The PDOC includes conditions to assure compliance with this rule.

The PDOC does not include a review of compliance with the NSPS Subpart IIII that is applicable to the emergency engines; however, the district's engine conditions, and staff's verification should ensure compliance with the requirements of this standard.

Rule 4002 – National Emission Standards for Hazardous Air Pollutants

Rule 4002 incorporates the National Emission Standards for Hazardous Air Pollutants (NESHAPs) from Part 61 and Part 63, Chapter I, Subchapter C, Title 40 CFR and applies to major sources of Hazardous Air Pollutants (HAPs). HECA will conduct an initial speciated HAPS compliance source test to demonstrate compliance and the PDOC includes conditions to assure compliance with this rule.

The PDOC does not include a review of compliance with the NESHAPs 40 CFR Part 63 Subpart ZZZZ that is applicable to the emergency engines; however, the district's engine conditions, and staff's verification should ensure compliance with the requirements of this standard.

Rule 4101 – Visible Emissions

This rule prohibits visible air emissions, other than water vapor, of more than No. 1 on the Ringelmann chart (20 percent opacity) for more than three minutes in any one-hour. Considering the control equipment (SCR/CO catalyst) on the gas turbine and other stationary sources, no visible emissions greater than 20 percent opacity are expected during normal operation of the facility. The PDOC includes conditions to assure compliance with this rule.

Rule 4102 – Nuisance

This rule prohibits any emissions "which 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 person or public or which cause or have a natural tendency to cause injury or damage to business or property." The types of emission sources at the facility, when operating normally, are not expected to cause the potential for nuisance. The PDOC includes a condition to assure compliance with this rule.

Rule 4201 – Particulate Matter Concentration

Rule 4201 limits particulates emissions from any source that emits or may emit dust, fumes, or total suspended particulate matter to less than 0.1 grain per dry standard cubic foot (gr/dscf) of gas calculated to 12 percent of carbon dioxide. The particulate matter grain loading expected for the proposed facility equipment are less than this standard. The PDOC includes a condition to assure compliance with this rule.

Rule 4202 – Particulate Matter Emission Rate

This rule limits particulate matter emissions for any source operation, which emits or may emit particulate matter emissions, by establishing allowable emission rates. Calculation methods for determining the emission rate based on process weight are specified. Gaseous and liquid fuels are exempt, so the turbines and the engines are exempt from this rule.

The project's proposed cooling towers and fuel feedstock handling equipment are subject to this rule and the emissions from the cooling towers were found to comply in the PDOC's engineering analysis and the PDOC includes conditions to assure compliance with this rule.

Rule 4301 – Fuel Burning Equipment

Rule 4301 provides limits on the concentration of combustion contaminants and specifies maximum emission rates for NOx, SO_2, and combustion contaminant emissions (particulates) for any fuel burning equipment, except for air pollution control equipment which is exempt. The specified limits are 140 lbs/hour of NOx, calculated as NO_2, 200 lbs/hour of SO_2, 0.1 gr/dscf of combustion contaminants in exhaust flue gas calculated to 12 percent of carbon dioxide, and 10 lbs/hour of combustion contaminants. The combustion turbine generator and emergency engines do not meet the definition of fuel burning equipment as stated in this rule and are therefore exempt. However, auxiliary boiler is subject to this rule, and the district has found that the maximum hourly emissions from the auxiliary boiler would be less than the emission limits set by this rule. Therefore, compliance with this rule is expected.

Rule 4311 – Flares

This rule limits emissions of VOC, NOx, and SOx from the operation of flares. All three flares (gasification flare, SRU flare, and rectisol flare) are subject to this rule. The PDOC includes conditions to assure compliance with this rule.

Rule 4320 – Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heater Greater Than 5.0 MMBtu/hr

This rule limits emissions of NOx, CO, SO_2, and PM10 emissions from permit units burning greater than 5 MMBtu/hr of fuel. The auxiliary boiler is subject to this rule, and the PDOC includes a condition to assure compliance with this rule.

Rule 4702 – Internal Combustion Engines – Phase 2

This rule limits emissions of NOx, CO, and VOC from internal combustion engines with a rated brake horsepower greater than 50 hp. Pursuant to Section 4.3.1.2, the proposed emergency engines are exempted, and only need to meet the following recording requirements of Section 6.2.3 of this Rule:

- 6.2.3.1 Total hours of operation,
- 6.2.3.2 The type of fuel used,
- 6.2.3.3 The purpose for operating the engine,
- 6.2.3.4 For emergency standby engines, all hours of non-emergency and emergency operation shall be reported, and
- 6.2.3.5 Other support documentation necessary to demonstrate claim to the exemption.

The PDOC includes conditions to assure compliance with this rule.

Rule 4703 – Stationary Gas Turbines

Rule 4703 limits NOx and CO emissions from stationary gas turbines. The rule establishes requirements for testing, monitoring, and record keeping for NOx and CO emissions from new or modified stationary gas turbines with a designed power of 0.3 MW or higher and/or a maximum heat input rating of more than 3,000,000 Btu per hour.

Hydrogen-rich fuel does not meet the definition of gas fuel as stated in this rule therefore this rule would not apply when the CTG is fired on hydrogen-rich fuel. However, the CTG is subject to this rule when fired on natural gas or co-fired with a blend of natural gas and hydrogen. The PDOC includes conditions to assure compliance with this rule.

Rule 4801 – Sulfur Compounds

Rule 4801 limits the emissions of sulfur compounds to no greater than 0.2 percent by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes. The use of PUC-regulated natural gas and CARB certified diesel fuel, and the district conditions providing fuel sulfur limits on the hydrogen-rich fuel will assure compliance with this rule.

Rule 7012 – Hexavalent Chromium – Cooling Towers

This rule limits emissions of hexavalent chromium from circulating water in cooling towers. Section 5.2.1 of this rule requires no hexavalent chromium containing compounds be added to cooling tower circulating water. The PDOC includes conditions to assure compliance with this rule.

REGULATION VIII - FUGITIVE PM10 PROHIBITIONS

The district has included several conditions in the PDOC that relate mitigation and compliance requirements of these rules (**AQ-9** to **AQ-18**) that would apply during project construction and operation. Staff's construction fugitive dust mitigation condition (**AQ-SC3**) generally includes the same requirements as these district rules but has been revised to note that any district rule requirement that is more stringent than those required in the Staff condition shall apply. The PDOC includes conditions to assure compliance with all Regulation VIII rules.

Rule 8011 – General Requirements

Rule 8011 specifies the types of chemical stabilizing agents and dust suppressant materials that can (and cannot) be used to minimize fugitive dust from anthropogenic (man-made) sources. The rule also specifies test methods for determining compliance with visible dust emission (VDE) standards and for stabilized surface conditions, soil moisture content, silt content for bulk materials, silt content for unpaved roads and unpaved vehicle/equipment traffic areas, and threshold friction velocity (TFV). The facility would be required to retain records only for those days that a control measure was implemented, and keep the records for one year following project completion to demonstrate compliance. An owner subject to Rule 2520 (Federally Mandated Operating Permits) shall keep such records for five years. A fugitive dust management plan for unpaved roads and unpaved vehicle/ equipment traffic areas is discussed as an alternative for Rule 8061 and Rule 8071. The PDOC includes conditions to assure compliance with Regulation VIII rules.

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

Rule 8021 requires fugitive dust emissions throughout construction activities (from pre-activity to active operations and during periods of inactivity) to comply with the conditions of a stabilized surface area and to not exceed an opacity limit of 20 percent, by means of water application, chemical dust suppressants, or constructing and maintaining wind barriers. A Dust Control Plan is also required and shall be submitted to the APCO prior to the start of any construction activities on any site that will include 10 acres or more of disturbed surface area for residential developments, 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. Compliance is expected.

Rule 8031 – Bulk Materials

Rule 8031 limits the fugitive dust emissions from the outdoor handling, storage and transport of bulk materials. This rule requires fugitive dust emissions to comply with the conditions of a stabilized unpaved road surface and to not exceed an opacity limit of 20 percent. It specifies that bulk materials be transported using wetting agents, allow appropriate freeboard space in the vehicles, or be covered. It also requires that stored materials be covered or stabilized. Compliance is expected.

Rule 8041 – Carryout and Trackout

Rule 8041 limits carryout and trackout during construction, demolition, excavation, extraction, and other earthmoving activities (Rule 8021), from bulk materials handling (Rule 8031), from paved and unpaved roads (Rule 8061), and from unpaved vehicle and equipment traffic areas (Rule 8071) where carryout has occurred or may occur. Carryout and trackout for this project is only related to the construction period and staff's construction fugitive dust mitigation condition **AQ-SC3** includes requirements to assure compliance with Regulation VIII rules. Compliance is expected.

Rule 8051 – Open Areas

Rule 8051 requires any open area of 0.5 acres or more within urban areas, or three acres or more within rural areas, and contains at least 1,000 square feet of disturbed surface area to comply with the conditions of a stabilized unpaved road surface and to not exceed an opacity limit of 20 percent, by means of water application, chemical dust suppressants, paving, applying and maintaining gravel, or planting vegetation. Compliance is expected.

Rule 8061 – Paved and Unpaved Roads

Rule 8061 specifies the width of paved shoulders on paved roads and guidelines for medians. It requires gravel, roadmix, paving, landscaping, watering, and/or the use of chemical dust suppressants on unpaved roadways to prevent exceeding an opacity limit of 20 percent. Exemptions to this rule include "any unpaved road segment with less than 26 annual average daily vehicle trips (AADT)." Compliance is expected.

Rule 8071 – Unpaved Vehicle/Equipment Traffic Areas

This rule intends to limit fugitive dust from any unpaved vehicle and equipment traffic area by using gravel, roadmix, paving, landscaping, watering, and/or the use of chemical dust suppressants to prevent exceeding an opacity limit of 20 percent. Exemptions to this rule include "unpaved vehicle and equipment traffic areas with less than 50 Average Annual Daily Trips (AADT)." Compliance is expected.

NOTEWORTHY PUBLIC BENEFITS

No air quality related noteworthy public benefits have been identified.

CONCLUSIONS

Staff has made the following preliminary conclusions about the HECA Project:

- Construction impacts would contribute to violations of the ozone, PM10, and PM2.5 ambient air quality standards. Staff recommends Conditions of Certification **AQ-SC1** to **AQ-SC5**, and district Conditions of Certification **AQ-9** to **AQ-18**, to mitigate the project construction-phase impacts to a less than significant level.
- The project's operation would neither cause new violations of any NO_2, CO, or SO_2 ambient air quality standards nor significantly contribute to existing violations for these pollutants. The HECA project's operation would result in a less than significant direct emissions impact under CEQA if HECA complies with all staff recommended and district required Conditions of Certification and provides the emission offsets, in quantities recommended by staff and the district (**AQ-2** through **AQ-6)**, and comply with all district conditions (**AQ-1** through **AQ-292**). Therefore, the project's direct NO_2, CO, and SO_2 impacts are less than significant.
- The proposed project's indirect (or secondary emissions) contribution to existing violations of the ozone and particulate (PM10/PM2.5) ambient air quality standards are likely CEQA significant if unmitigated. Therefore, staff recommends **AQ-SC7** to mitigate the onsite maintenance vehicle emissions to reduce their ozone precursor emissions; and district conditions **AQ-9** to **AQ-18** mitigate the non-stationary source operating fugitive dust emissions potential to ensure that the both the potential ozone and PM10/PM2.5 CEQA impacts are mitigated to less than significant over the life of the project.
- The project will continue to operate in compliance with adoption of staff's proposed condition **AQ-SC6** that provides the administrative procedural requirements for project modifications and condition **AQ-SC8** that requires quarterly operations compliance reporting.
- Staff has considered the minority population surrounding the site (see Socioeconomics Figure 1). Since the project's direct and cumulative air quality impacts have been reduced to less than significant, there is no environmental justice issue for air quality.

PROPOSED CONDITIONS OF CERTIFICATION

Staff recommends the following conditions of certification to address the impacts associated with the construction and operation of the HECA project. These Conditions include the SJVAPCD proposed Conditions from the PDOC, with appropriate staff proposed verification language added for each condition, as well as Energy Commission staff proposed conditions.

STAFF CONDITIONS

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4** and **AQ-SC5** for the entire project site and linear facility construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM Delegates. The AQCMM and AQCMM Delegates shall have full access to all areas of construction on the project site and linear facilities, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM Delegates may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the Compliance Project Manager (CPM).

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval, the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM Delegates.

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4,** and **AQ-SC5**.

Verification: At least 30 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The AQCMP shall include effectiveness and environmental data for the proposed soil stabilizer. The CPM will notify the project owner of any necessary modifications to the plan within 15 days from the date of receipt.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report that demonstrates compliance with the Air Quality Construction Mitigation Plan (AQCMP) mitigation measures for the purposes of minimizing fugitive dust emission creation from construction activities and preventing all fugitive dust plumes that would not comply with the performance standards identified in **AQ-SC4** from leaving the project site. The following fugitive dust mitigation measures shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**, and any deviation from the AQCMP mitigation measures shall require prior CPM notification and approval.

a. The main access roads through the facility from the main public road access to the fuel receiving and storage and gasification and power block areas will be paved prior to initiating construction of structures within the fuel receiving and storage and gasification and power block areas.

b. All unpaved construction roads and unpaved operation and maintenance site roads including roads to all well pads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as ARB approved soil stabilizers, and shall not increase any other environmental impacts, including loss of vegetation to areas beyond where the soil stabilizers are being applied for dust control. All other disturbed areas in the project and linear construction sites shall be watered as frequently as necessary during grading (consistent with Biology Conditions of Certification that address the minimization of standing water); and after active construction activities shall be stabilized with a non-toxic soil stabilizer or soil weighting agent, or alternative approved soil stabilizing methods, in order to comply with the dust mitigation objectives of Condition of Certification **AQ-SC4**. The frequency of watering can be reduced or eliminated during periods of precipitation.

c. No vehicle shall exceed a speed of 10 miles per hour on unpaved areas within the construction site, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

d. Visible speed limit signs shall be posted at the construction site entrances.

e. All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

f. Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

g. All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

h. All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

i. Construction areas adjacent to any paved roadway below the grade of the surrounding construction area or otherwise directly impacted by sediment from site drainage shall be provided with sandbags or other equivalently effective measures to prevent run-off to roadways, or other similar run-off control measures as specified in the Storm Water Pollution Prevention Plan (SWPPP), only when such SWPPP measures are necessary so that this condition does not conflict with the requirements of the SWPPP.

j. All paved roads within the construction site shall be swept daily or as needed (less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

k. At least the first 500 feet of any paved public roadway exiting the construction site or exiting other unpaved roads en route from the construction site or construction staging areas shall be swept as needed (less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff resulting from the construction site activities is visible on the public paved roadways.

l. All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or shall be treated with appropriate dust suppressant compounds.

m. All vehicles that are used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.

n. Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

o. The fugitive dust control requirements of SJVAPCD Regulation VIII that are in addition to or more stringent than the requirements of parts a. through n. of this condition shall be identified in the AQCMP (**AQ-SC2**), and performed as necessary for compliance with SJVAPCD Rules and Regulations and Conditions **AQ-9** through **AQ-18**.

Verification: The AQCMM shall provide the CPM a Monthly Compliance Report to include the following to demonstrate control of fugitive dust emissions:

A. a summary of all actions taken to maintain compliance with this condition;

B. copies of any complaints filed with the district in relation to project construction; and

C. any other documentation deemed necessary by the CPM or AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 Dust Plume Response Requirement: The AQCMM or an AQCMM Delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported (A) off the project site and within 400 feet upwind of any regularly occupied structures not owned by the project owner or (B) 200 feet beyond the centerline of the construction of linear facilities indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified. The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed:

Step 1: The AQCMM or Delegate shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

Step 2: The AQCMM or Delegate shall direct implementation of additional methods of dust suppression if Step 1, specified above, fails to result in adequate mitigation within 30 minutes of the original determination.

Step 3: The AQCMM or Delegate shall direct a temporary shutdown of the activity causing the emissions if Step 2, specified above, fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or Delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or Delegate to shut down an activity, if the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

<u>Verification:</u> The AQCMM shall provide the CPM a Monthly Compliance Report to include:

A. a summary of all actions taken to maintain compliance with this condition;

B. copies of any complaints filed with the district in relation to project construction; and

C. any other documentation deemed necessary by the CPM or AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner’s discretion.

AQ-SC5 Diesel-Fueled Engine Control: The AQCMM shall submit to the CPM, in the Monthly Compliance Report, a construction mitigation report that demonstrates compliance with the AQCMP mitigation measures for purposes of controlling diesel construction-related emissions. The following off-road diesel construction equipment mitigation measures shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**, and any deviation from the AQCMP mitigation measures shall require prior CPM notification and approval.

a. All diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein.

b. All construction diesel engines with a rating of 50 hp or higher shall meet, at a minimum, the Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines, as specified in California Code of Regulations, Title 13, section 2423(b)(1), unless a good faith effort to the satisfaction of the CPM that is certified by the on-site AQCMM demonstrates that such engine is not available for a particular item of equipment. In the event that a Tier 3 engine is not available for any off-road equipment larger than 50 hp, that equipment shall be equipped with a Tier 2 engine, or an engine that is equipped with retrofit controls to reduce exhaust emissions of nitrogen oxides (NOx) and diesel particulate matter (DPM) to no more than Tier 2 levels unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is “not practical” for the following, as well as other, reasons.

1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. Environmental Protection Agency to control the engine in question to Tier 2 equivalent emission levels and the highest level of available control using retrofit or Tier 1 engines is being used for the engine in question; or

2. The construction equipment is intended to be on site for 10 work days or less.

3. The CPM may grant relief from this requirement if the AQCMM can demonstrate a good faith effort to comply with this requirement and that compliance is not practical.

c. The use of a retrofit control device may be terminated immediately, provided that the CPM is informed within 10 working days of the termination and that a replacement for the equipment item in question meeting the controls required in item “b” occurs within 10 work days of termination of the use, if the equipment would be needed to continue working at this site for more than 15 work days after the use of the retrofit control device is terminated, if one of the following conditions exists:

    1. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive increase in back pressure.

    2. The retrofit control device is causing or is reasonably expected to cause engine damage.

    3. The retrofit control device is causing or is reasonably expected to cause a substantial risk to workers or the public.

    4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.

d. All heavy earth-moving equipment and heavy duty construction-related trucks with engines meeting the requirements of (b) above shall be properly maintained and the engines tuned to the engine manufacturer’s specifications.

e. All diesel heavy construction equipment shall not idle for more than five minutes. Vehicles that need to idle as part of their normal operation (such as concrete trucks) are exempted from this requirement.

f. Construction equipment will employ electric motors when feasible.

Verification: The AQCMM shall include in the Monthly Compliance Report the following to demonstrate control of diesel construction-related emissions:

A. A summary of all actions taken to control diesel construction related emissions;

B. A list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that equipment has been properly maintained; and

C. Any other documentation deemed necessary by the CPM, and the AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC6 The project owner shall provide the CPM copies of all district issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) documents for the facility. The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project federal air permit. The project owner shall submit to the CPM any modification to any federal air permit proposed by the district or U.S. Environmental Protection Agency (U.S. EPA), and any revised federal air permit issued by the district or U.S. EPA, for the project.

Verification: The project owner shall submit any ATC, PTO, and proposed federal air permit modifications to the CPM within 5 working days of either: 1) submittal by the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified ATC/PTO documents and all federal air permits to the CPM within 15 days of receipt.

AQ-SC7 The project owner, when obtaining dedicated on-road or off-road vehicles for coke and coal handling, gasifier solids handling, or facility maintenance activities, shall only obtain vehicles that meet California on-road vehicle emission standards or appropriate U.S. EPA/California off-road engine emission standards for the latest model year available when obtained.

Verification: At least 30 days prior to the start commercial operation, the project owner shall submit to the CPM a copy of the plan that identifies the size and type of the on-site vehicle and equipment fleet and the vehicle and equipment purchase orders and contracts and/or purchase schedule. The plan shall be updated every other year and submitted in the Annual Compliance Report.

AQ-SC8 The project owner shall submit to the CPM quarterly operation reports that include operational and emissions information as necessary to demonstrate compliance with the conditions of certification. The quarterly operation report shall specifically note or highlight incidences of noncompliance.

Verification: The project owner shall submit quarterly operation reports to the CPM, and district if requested, no later than 30 days following the end of each calendar quarter. This information shall be maintained on site for a minimum of five years and shall be provided to the CPM and district personnel upon request.

AQ-SC9 The project owner shall control the fugitive emissions from the inactive coke storage pile so that there are no visible emissions by either 1) covering the pile, or 2) through the use of an approved surface stabilizing compound. If the project owner chooses not to cover the pile they shall demonstrate compliance through visible emission tests, using EPA Method 9, downwind of the coke storage pile at least quarterly and at least once a day when the average wind speeds exceed twenty miles per hour.

Verification: The project owner shall submit the method of coke storage pile emission mitigation, including the specifications of the surface stabilizing compound if used, to the CPM for approval at least 60 days prior to unloading coke into the storage pile. A summary of the visual emissions monitoring, if required, will be provided in the Quarterly Operation Reports (AQ-SC8) and these records shall be maintained onsite for a minimum of two years and shall be provided to the CPM and district personnel upon request.

DISTRICT PRELIMINARY DETERMINATION OF COMPLIANCE CONDITIONS (SJVAPCD 2010c)

The SJVACPD permits each device separately, which causes duplication of conditions. Staff has compiled the SJVAPCD conditions to eliminate this duplication as shown in the following referencing table.

District Condition No.	Staff Condition No.
Combustion Turbine/HRSG with Duct Burner (S-7616-9-0)	
1	AQ-1
2	AQ-2
3	AQ-3
4	AQ-4
5	AQ-5
6	AQ-6
7	AQ-7
8	AQ-8
9	AQ-19
10	AQ-20
11	AQ-21
12	AQ-22
13	AQ-23
14	AQ-24
15	AQ-25
16	AQ-26
17	AQ-27
18	AQ-28
19	AQ-29
20	AQ-30
21	AQ-31
22	AQ-32
23	AQ-33

District Condition No.	Staff Condition No.
24	AQ-34
25	AQ-35
26	AQ-36
27	AQ-37
28	AQ-38
29	AQ-39
30	AQ-40
31	AQ-41
32	AQ-42
33	AQ-43
34	AQ-44
35	AQ-45
36	AQ-46
37	AQ-47
38	AQ-48
39	AQ-49
40	AQ-50
41	AQ-51
42	AQ-52
43	AQ-53
44	AQ-54
45	AQ-55
46	AQ-56
47	AQ-57
48	AQ-58

District Condition No.	Staff Condition No.
49	AQ-59
50	AQ-60
51	AQ-61
52	AQ-62
53	AQ-63
54	AQ-64
55	AQ-65
56	AQ-66
57	AQ-67
58	AQ-68
59	AQ-69
60	AQ-70
61	AQ-71
62	AQ-72
63	AQ-73
64	AQ-74
65	AQ-75
66	AQ-76
67	AQ-77
68	AQ-78
69	AQ-79
70	AQ-80
71	AQ-9
72	AQ-10
73	AQ-11
74	AQ-12
75	AQ-13
76	AQ-14
77	AQ-15
78	AQ-16
79	AQ-17
80	AQ-18
81	AQ-81
82	AQ-82
83	AQ-83
84	AQ-84
85	AQ-85
Feedstock Handling System (S-7616-1-0)	
1	AQ-1
2	AQ-3
3	AQ-6
4	AQ-7
5	AQ-8
6	AQ-86
7	AQ-87
8	AQ-88

District Condition No.	Staff Condition No.
9	AQ-89
10	AQ-90
11	AQ-91
12	AQ-92
13	AQ-93
14	AQ-94
15	AQ-95
16	AQ-96
17	AQ-97
18	AQ-98
19	AQ-99
20	AQ-100
21	AQ-101
22	AQ-102
23	AQ-103
24	AQ-104
25	AQ-105
26	AQ-106
27	AQ-107
28	AQ-108
29	AQ-109
30	AQ-110
31	AQ-111
32	AQ-112
33	AQ-113
34	AQ-114
35	AQ-9
36	AQ-10
37	AQ-11
38	AQ-12
39	AQ-13
40	AQ-14
41	AQ-15
42	AQ-16
43	AQ-17
44	AQ-18
Gasification System (S-7616-2-0)	
1	AQ-1
2	AQ-2
3	AQ-3
4	AQ-4
5	AQ-5
6	AQ-6
7	AQ-7
8	AQ-8
9	AQ-115

District Condition No.	Staff Condition No.
10	AQ-116
11	AQ-117
12	AQ-118
13	AQ-119
14	AQ-120
15	AQ-121
16	AQ-122
17	AQ-123
18	AQ-124
19	AQ-125
20	AQ-126
21	AQ-127
22	AQ-128
23	AQ-129
24	AQ-130
25	AQ-131
26	AQ-132
27	AQ-133
28	AQ-134
29	AQ-135
30	AQ-136
31	AQ-137
32	AQ-138
33	AQ-9
34	AQ-10
35	AQ-11
36	AQ-12
37	AQ-13
38	AQ-14
39	AQ-15
40	AQ-16
41	AQ-17
42	AQ-18
Sulfur Recovery System (S-7616-5-0)	
1	AQ-1
2	AQ-2
3	AQ-3
4	AQ-4
5	AQ-5
6	AQ-6
7	AQ-7
8	AQ-8
9	AQ-139
10	AQ-140
11	AQ-141
12	AQ-142

District Condition No.	Staff Condition No.
13	AQ-143
14	AQ-144
15	AQ-145
16	AQ-146
17	AQ-147
18	AQ-148
19	AQ-149
20	AQ-150
21	AQ-151
22	AQ-152
23	AQ-153
24	AQ-154
25	AQ-155
26	AQ-156
27	AQ-157
28	AQ-158
29	AQ-159
30	AQ-160
31	AQ-161
32	AQ-162
33	AQ-163
34	AQ-164
35	AQ-165
36	AQ-166
37	AQ-167
38	AQ-168
39	AQ-169
40	AQ-170
41	AQ-171
42	AQ-172
43	AQ-173
44	AQ-174
45	AQ-175
46	AQ-9
47	AQ-10
48	AQ-11
49	AQ-12
50	AQ-13
51	AQ-14
52	AQ-15
53	AQ-16
54	AQ-17
55	AQ-18
Gasifier Flare (S-7616-3-0)	
1	AQ-1
2	AQ-2

District Condition No.	Staff Condition No.
3	AQ-3
4	AQ-4
5	AQ-5
6	AQ-6
7	AQ-7
8	AQ-8
9	AQ-189
10	AQ-190
11	AQ-191
12	AQ-176
13	AQ-192
14	AQ-193
15	AQ-194
16	AQ-195
17	AQ-196
18	AQ-197
19	AQ-177
20	AQ-178
21	AQ-179
22	AQ-198
23	AQ-180
24	AQ-181
25	AQ-182
26	AQ-183
27	AQ-184
28	AQ-185
29	AQ-186
30	AQ-187
31	AQ-199
32	AQ-200
33	AQ-201
34	AQ-202
35	AQ-203
36	AQ-204
37	AQ-205
38	AQ-188
39	AQ-9
40	AQ-10
41	AQ-11
42	AQ-12
43	AQ-13
44	AQ-14
45	AQ-15
46	AQ-16
47	AQ-17
48	AQ-18

District Condition No.	Staff Condition No.
Sulfur Recovery Flare (S-7616-6-0)	
1	AQ-1
2	AQ-2
3	AQ-3
4	AQ-4
5	AQ-5
6	AQ-6
7	AQ-7
8	AQ-8
9	AQ-206
10	AQ-207
11	AQ-208
12	AQ-176
13	AQ-209
14	AQ-210
15	AQ-211
16	AQ-212
17	AQ-177
18	AQ-178
19	AQ-179
20	AQ-213
21	AQ-180
22	AQ-181
23	AQ-182
24	AQ-183
25	AQ-184
26	AQ-185
27	AQ-186
28	AQ-187
29	AQ-214
30	AQ-215
31	AQ-216
32	AQ-217
33	AQ-218
34	AQ-219
35	AQ-220
36	AQ-221
37	AQ-222
38	AQ-223
39	AQ-224
40	AQ-225
41	AQ-226
42	AQ-227
43	AQ-228
44	AQ-229
45	AQ-188

District Condition No.	Staff Condition No.
46	AQ-9
47	AQ-10
48	AQ-11
49	AQ-12
50	AQ-13
51	AQ-14
52	AQ-15
53	AQ-16
54	AQ-17
55	AQ-18
Rectisol Acid Emergency Flare (S-7616-7-0)	
1	AQ-1
2	AQ-2
3	AQ-3
4	AQ-4
5	AQ-5
6	AQ-6
7	AQ-7
8	AQ-8
9	AQ-230
10	AQ-231
11	AQ-176
12	AQ-232
13	AQ-177
14	AQ-178
15	AQ-179
16	AQ-180
17	AQ-233
18	AQ-181
19	AQ-182
20	AQ-183
21	AQ-184
22	AQ-185
23	AQ-186
24	AQ-187
25	AQ-234
26	AQ-235
27	AQ-188
28	AQ-9
29	AQ-10
30	AQ-11
31	AQ-12
32	AQ-13
33	AQ-14
34	AQ-15
35	AQ-16

District Condition No.	Staff Condition No.
36	AQ-17
37	AQ-18
Carbon Dioxide Recovery Unit (S-7616-8-0)	
1	AQ-1
2	AQ-5
3	AQ-6
4	AQ-7
5	AQ-8
6	AQ-236
7	AQ-237
8	AQ-238
9	AQ-239
10	AQ-240
11	AQ-241
12	AQ-242
13	AQ-243
14	AQ-9
15	AQ-10
16	AQ-11
17	AQ-12
18	AQ-13
19	AQ-14
20	AQ-15
21	AQ-16
22	AQ-17
23	AQ-18
Gasification Cooling Tower (S-7616-4-0)	
1	AQ-1
2	AQ-3
3	AQ-6
4	AQ-7
5	AQ-8
6	AQ-244
7	AQ-245
8	AQ-246
9	AQ-247
10	AQ-248
11	AQ-249
12	AQ-250
13	AQ-251
14	AQ-252
15	AQ-253
16	AQ-9
17	AQ-10
18	AQ-11
19	AQ-12

District Condition No.	Staff Condition No.
20	AQ-13
21	AQ-14
22	AQ-15
23	AQ-16
24	AQ-17
25	AQ-18
Air Separation Unit Cooling Tower (S-7616-11-0)	
1	AQ-1
2	AQ-3
3	AQ-6
4	AQ-7
5	AQ-8
6	AQ-244
7	AQ-245
8	AQ-246
9	AQ-247
10	AQ-248
11	AQ-249
12	AQ-250
13	AQ-251
14	AQ-252
15	AQ-253
16	AQ-9
17	AQ-10
18	AQ-11
19	AQ-12
20	AQ-13
21	AQ-14
22	AQ-15
23	AQ-16
24	AQ-17
25	AQ-18
Power Block Cooling Tower (S-7616-12-0)	
1	AQ-1
2	AQ-3
3	AQ-6
4	AQ-7
5	AQ-8
6	AQ-244
7	AQ-245
8	AQ-246
9	AQ-247
10	AQ-248
11	AQ-249
12	AQ-250

District Condition No.	Staff Condition No.
13	AQ-251
14	AQ-252
15	AQ-253
16	AQ-9
17	AQ-10
18	AQ-11
19	AQ-12
20	AQ-13
21	AQ-14
22	AQ-15
23	AQ-16
24	AQ-17
25	AQ-18
Auxiliary Boiler (S-7616-13-0)	
1	AQ-1
2	AQ-2
3	AQ-3
4	AQ-4
5	AQ-5
6	AQ-6
7	AQ-7
8	AQ-8
9	AQ-254
10	AQ-255
11	AQ-256
12	AQ-257
13	AQ-258
14	AQ-259
15	AQ-260
16	AQ-261
17	AQ-262
18	AQ-263
19	AQ-264
20	AQ-265
21	AQ-266
22	AQ-267
23	AQ-268
24	AQ-269
25	AQ-270
26	AQ-271
27	AQ-272
28	AQ-273
29	AQ-274
30	Duplicate (28, AQ-273)
31	AQ-275
32	AQ-9

District Condition No.	Staff Condition No.
33	AQ-10
34	AQ-11
35	AQ-12
36	AQ-13
37	AQ-14
38	AQ-15
39	AQ-16
40	AQ-17
41	AQ-18
Emergency Generators (S-7616-14-0) & (S-7616-15-0)	
1	AQ-1
2	AQ-276
3	AQ-277
4	AQ-278
5	AQ-279
6	AQ-280
7	AQ-281
8	AQ-282
9	AQ-283
10	AQ-284
11	AQ-285
12	AQ-286
13	AQ-287
14	AQ-288
15	AQ-291
16	AQ-289
17	AQ-290
18	AQ-9
19	AQ-10
20	AQ-11
21	AQ-12
22	AQ-13
23	AQ-14
24	AQ-15
25	AQ-16
26	AQ-17
27	AQ-18
Emergency Fire Water Pump (S-7616-16-0)	
1	AQ-1
2	AQ-276
3	AQ-277
4	AQ-278
5	AQ-279
6	AQ-280
7	AQ-281

District Condition No.	Staff Condition No.
8	AQ-282
9	AQ-283
10	AQ-284
11	AQ-285
12	AQ-286
13	AQ-287
14	AQ-288
15	AQ-292
16	Duplicate (15, AQ-292)
17	AQ-289
18	AQ-290
19	AQ-9
20	AQ-10
21	AQ-11
22	AQ-12
23	AQ-13
24	AQ-14
25	AQ-15
26	AQ-16
27	AQ-17
28	AQ-18

GENERAL FACILITY CONDITIONS

AQ-1 The project owner shall enter into an Air Quality Mitigation Settlement Agreement with the district prior to issuance of the Final Determination of Compliance, or such other time that is mutually agreeable.

Verification: The project owner shall submit to both the district and CPM records of the project's Air Quality Mitigation Settlement Agreement prior to issuance of the Final Determination of Compliance.

AQ-2 Prior to initial operation of S-7616-2, -3, -5, -6, -7, -9, and -13, the project owner shall provide NOx emission reduction credits for the following quantity of emissions: 1st quarter: 92,319 lb, 2nd quarter: 92,319 lb, 3rd quarter: 92,319 lb, and 4th quarter: 92,319 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the district and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-3 Prior to initial operation of S-7616-1 through -7 and -9 through -13, the project owner shall provide PM10 emission reduction credits for the following quantity of emissions: 1st quarter: 48,489 lb, 2nd quarter - 48,489 lb, 3rd quarter: 48,489 lb, and 4th quarter: 48,489 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). SOx ERCs may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx: 1.0 lb-PM10. [District Rule 2201]

Verification: The project owner shall submit to both the district and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-4 Prior to initial operation of S-7616-2, -3, -5, -6, -7, -9, and -13, the project owner shall provide SOx emission reduction credits for the following quantity of emissions: 1st quarter: 5,315 lb, 2nd quarter: 5,315 lb, 3rd quarter: 5,315 lb, and 4th quarter: 5,315 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the district and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-5 Prior to initial operation of S-7616-2, -3, -5 through -9, and -13, the project owner shall provide VOC emission reduction credits for the following quantity of emissions: 1st quarter: 31,817 lb, 2nd quarter: 31,817 lb, 3rd quarter: 31,817 lb, and 4th quarter: 31,817 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

Verification: The project owner shall submit to both the district and CPM records showing that the project's offset requirements have been met prior to initiating operation.

AQ-6 ERC certificate numbers C-1058-2, C-1058-5, C-1059-2, S-3275-5, S-3273-2, S-3305-1, and/or S-3306-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the district, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Demonstration of Compliance. [District Rule 2201]

Verification: The project owner shall submit to the CPM a list of the ERC certificates and quantities surrendered to the district within 30 days of their surrender. The project owner shall request any changes to the ERC certificates listed in this condition at least 30 days prior to their surrender date. If the CPM, in consultation with the district, approves a substitution or modification, the CPM shall file a statement of the approval with the commission docket and mail a copy of the statement to every person on the post-certification mailing list. The CPM shall maintain an updated list of approved ERCs for the project. The initial table of the approved list of ERCs is as follows:

HECA Approved ERC List

ERC Certificate	Pollutant	1st Quarter lbs	2nd Quarter lbs	3rd Quarter lbs	4th Quarter lbs
S-3305-1	VOC	14,625	14,625	14,625	14,625
S-3306-1 (split)	VOC	11,437.5	11,437.5	11,437.5	11,437.5
S-3306-1 (split)	VOC	7,937.5	7,937.5	7,937.5	7,937.5
S-3273-2	NOx	120,500	120,500	120,500	120,500
C-1058-2	NOx	10,100	10,100	10,100	10,100
C-1059-2	NOx	21,900	21,900	21,900	21,900
S-3275-5	SOx	42,000	42,000	42,000	42,000
C-1058-5	SOx	24,500	24,500	24,500	24,500
C-1059-5	SOx	70,500	70,500	70,500	70,500

AQ-7 The project owner shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Verification: The project owner shall submit to both the district and CPM the Operating Permit application within twelve months of commencing operation.

AQ-8 The project owner shall submit an application to comply with Rule 2540 - Acid Rain Program within twelve months of commencing operation. [District Rule 2540]

<u>Verification:</u> The project owner shall submit to both the district and CPM the Acid Rain Program application within twelve months of commencing operation.

AQ-9 Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

<u>Verification:</u> The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition during facility operation in the Annual Compliance Reports. During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions **AQ-SC2** through **AQ-SC4.**

AQ-10 The project owner shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

<u>Verification:</u> The Dust Control Plan required under this condition, which will be coordinated with the plan and dust control requirements of **AQ-SC2** and **AQ-SC3**, shall be provided to the CPM and APCO at the same time, and if desired as part of plan required under **AQ-SC2**.

AQ-11 The project owner shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

<u>Verification:</u> The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition during facility operation in the Annual Compliance Reports. During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions **AQ-SC2** through **AQ-SC4.**

AQ-12 Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

<u>Verification:</u> The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition during facility operation in the Annual Compliance Reports. During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions **AQ-SC2** through **AQ-SC4.**

AQ-13 Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

<u>Verification:</u> The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition during facility operation in the Annual Compliance Reports. During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions **AQ-SC2** through **AQ-SC4.**

AQ-14 Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other district-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

<u>Verification:</u> The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition during facility operation in the Annual Compliance Reports. During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions **AQ-SC2** through **AQ-SC4.**

AQ-15 Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

<u>Verification:</u> The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition during facility operation in the Annual Compliance Reports. During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions **AQ-SC2** through **AQ-SC4.**

AQ-16 On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, the project owner shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other district-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

<u>Verification:</u> The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition during facility operation in the Annual Compliance Reports. During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions **AQ-SC2** through **AQ-SC4.**

AQ-17 Whenever any portion of the site becomes inactive, the project owner shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

<u>Verification:</u> The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition during facility operation in the Annual Compliance Reports. During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions **AQ-SC2** through **AQ-SC4.**

AQ-18 Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions.

Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

Verification: The project owner shall provide a summary of the fugitive dust mitigation measures performed as necessary to comply with this condition during facility operation in the Annual Compliance Reports. During construction the facility will comply with the mitigation measures and reporting/recordkeeping requirements of conditions **AQ-SC2** through **AQ-SC4.**

EQUIPMENT DESCRIPTION, UNIT S-7616-9-0

349 MW (gross) combined-cycle power generating system consisting of hydrogen-rich fuel and/or natural gas-fired GE PG7321 (FB) combined-cycle combustion turbine generator (CTG) with a heat recovery steam generator (HRSG) which includes a duct burner, selective catalytic reduction (SCR) system, carbon monoxide catalyst system; and a condensing steam turbine generator (STG) operating in combined cycle mode.

AQ-19 The project owner of the facility shall minimize the emissions from the gas turbine to the maximum extent possible during the commissioning period. **AQ-20** through **AQ-29** shall apply only during the commissioning period as defined below. Unless otherwise indicated, **AQ-9** through **AQ-18** and **AQ-30** through **AQ-85** shall apply after the commissioning period has ended. [District Rule 2201]

Verification: The project owner shall submit to the CPM and APCO for approval the commissioning plan as required in **AQ-25**, and shall submit to the CPM the Monthly Compliance Report identifying the steps the project owner is taking to comply with this condition.

Commissioning Period

AQ-20 Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to insure safe and reliable steady state operation of the gas turbines and associated electrical delivery systems. [District Rule 2201]

Verification: No verification necessary.

AQ-21 Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]

Verification: The project owner shall submit to the CPM in the Monthly Compliance Reports the date of commencement and completion of the initial commissioning of the gas turbine.

AQ-22 At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions. [District Rule 2201]

Verification: The project owner shall submit to the CPM in the Monthly Compliance Reports information detailing how the project owner is complying with the requirements of this condition.

AQ-23 At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the Selective Catalytic Reduction (SCR) system and the oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

Verification: The project owner shall submit to the CPM in the Monthly Compliance Reports information detailing how the project owner is complying with the requirements of this condition.

AQ-24 Coincident with the steady-state operation of the SCR system and the oxidation catalyst at loads greater than 50% and after installation and tuning of the emission controls, NOx, CO, and VOC emissions from this unit shall comply with the limits specified in **AQ-47**. [District Rule 2201]

Verification: The project owner shall submit to the CPM in the Monthly Compliance Reports information demonstrating compliance with the emission limits required in this condition.

AQ-25 The project owner shall submit a plan to the district at least four weeks prior to the first firing of this unit, describing the procedures to be followed during the commissioning period. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not limited to, the tuning of the combustors, the installation and operation of the SCR system and the oxidation catalyst, the installation, calibration, and testing of the NOx and CO continuous emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system or oxidation catalyst. [District Rule 2201]

Verification: The project owner shall submit, at least four weeks prior to fire firing of the gas turbine, to the APCO for approval and the CPM for review the commissioning plan for the gas turbine.

AQ-26 When firing on natural gas, emission rates from the CTG during the commissioning period shall not exceed any of the following limits: NOx (as NO_2) - 345.0 lb/hr; SOx - 4.7 lb/hr; PM10 - 18.0 lb/hr; CO - 2,200.0 lb/hr; or VOC (as methane) - 345.0 lb/hr. When firing on hydrogen-rich fuel, emission rates from the CTG during the commissioning period shall not exceed any of the following limits: NOx (as NO_2) - 167.0 lb/hr; SOx - 3.1 lb/hr; PM10 - 36.0 lb/hr; CO - 394.0 lb/hr; or VOC (as methane) - 98.0 lb/hr. [District Rule 2201]

Verification: The project owner shall submit to the CPM in the Monthly Compliance Reports information demonstrating compliance with the emission limits required in this condition.

AQ-27 During the commissioning period, the project owner shall demonstrate NOx and CO compliance with **AQ-26** through the use of properly operated and maintained continuous emissions monitors and recorders as specified in this document. The monitored parameters for this unit shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation). [District Rule 2201]

Verification: The project owner shall submit to the CPM in the Monthly Compliance Reports information demonstrating compliance with the continuous emissions monitoring requirements in this condition.

AQ-28 The continuous emissions monitors specified in these permit conditions shall be installed, calibrated and operational prior to the first firing of the unit. After first firing, the detection range of the CEMS shall be adjusted as necessary to accurately measure the resulting range of NOx and CO emissions concentrations. [District Rule 2201]

Verification: The project owner shall submit to the CPM in the Monthly Compliance Reports information demonstrating compliance with the continuous emissions monitoring requirements in this condition.

AQ-29 The total number of firing hours of this unit without abatement of emissions by the SCR system and the oxidation catalyst shall not exceed 892 hours total during the commissioning period on natural gas and 644 hours during the commissioning period on hydrogen-rich fuel. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and the oxidation catalyst in place. Upon completion of these activities, the project owner shall provide written notice to the district and the unused balance of the firing hours without abatement shall expire. Records of the commissioning hours of operation for the unit shall be maintained. [District Rule 2201]

Verification: A summary of the gas turbine operations during initial commissioning shall be provided to the CPM in the final Monthly Compliance Report demonstrating compliance with the requirements of this condition.

Post-Commissioning Period

AQ-30 The total mass emissions of NOx, SOx, PM10, CO, and VOC that are emitted during the commissioning period shall accrue towards the consecutive twelve month emission limits specified in **AQ-48**. NOx and CO total mass emissions will be determined from CEMs data and SOx, PM10, and VOC total mass emissions will be calculated. [District Rule 2201]

Verification: The consecutive twelve month emissions summary provided in the Quarterly Operation Reports (**AQ-SC8**) shall clearly identify the initial commissioning emissions when the initial commissioning emissions occur within the 12 month reporting period of the Quarterly Operation Reports.

AQ-31 A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine engine. Exhaust ducting may be equipped (if required) with a fresh air inlet blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. The project owner shall submit SCR and oxidation catalyst design details to the district at least 30 days prior to commencement of construction. [District Rule 2201]

Verification: The project owner shall provide the SCR system and oxidation catalyst system design plans to the APCO for approval and the CPM for review at least 30 days prior to commencement of construction.

AQ-32 The project owner shall submit continuous emission monitor design, installation, and operational details to the district at least 30 days prior to commencement of construction. [District Rule 2201]

Verification: The project owner shall provide a Continuous Emission Monitoring System (CEM) design plan to the APCO for approval and the CPM for review at least 30 days prior to commencement of construction.

AQ-33 The project owner shall submit to the district information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the district to determine compliance with the NOx emission limits of this permit when no continuous emission monitoring data for NOx is available or when the continuous emission monitoring system is not operating properly. [District Rule 4703]

Verification: The project owner shall provide the APCO for approval and the CPM for review NOx control system operations versus measured NOx emissions correlations after each NOx source test performed for this unit.

AQ-34 All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-35 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-36 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-37 Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-38 Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exhibit opacity of 5% or greater, except for a period or periods not exceeding three minutes in any one hour. [District Rules 2201 and 4101]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-39 This unit shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 0.75 grain of sulfur compounds (as S) per 100 dry scf of natural gas, hydrogen-rich fuel with a sulfur content no greater than 5 ppmv, or a combination of both fuels. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Verification: The project owner shall submit the fuel sulfur content data as required in **AQ-56** demonstrating compliance with this condition in the Quarterly Operation Reports (**AQ-SC8**).

AQ-40 Emission rates from the combustion turbine generator, except during startup and shutdown periods, shall not exceed any of the following: NOx (as NO_2) - 21.0 lb/hr and 2.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average) or 2.5 ppmvd @ 15% O_2 (1-hour average), (except during startup/shutdown); VOC (as methane) - 5.5 lb/hr and 1.0 ppmvd-VOC @ 15% O_2 when firing on hydrogen-rich fuel exclusively and 1.5 ppmvd @ 15% O_2 when firing on fuel containing natural gas; CO - 25.6 lb/hr and 3.0 ppmvd-CO @ 15% O_2 when firing on hydrogen-rich fuel exclusively and 4.0 ppmvd-CO @ 15% O_2 when firing on fuel containing natural gas; PM10 - 19.8 lb/hr; or SOx (as SO_2) - 6.8 lb/hr. The hourly rolling averages for NOx (as NO_2) emission limits indicated above. All other pollutant emission limits are three-hour rolling averages. [District Rules 2201 and 4703 and 40 CFR 60.4320(a) & (b)]

Verification: The project owner shall submit continuous monitoring data in summary form for pollutants that are continuously monitored, and the most recent source test data for pollutants that are not continuously monitored demonstrating compliance with this condition in the Quarterly Operation Reports (**AQ-SC8**).

AQ-41 Ammonia (NH_3) emissions shall not exceed either of the following limits: 19.4 lb/hr or 5 ppmvd @ 15% O_2 (based on a 24 hour rolling average). [District Rule 2201]

Verification: The project owner shall submit data, using the procedures outlined in **AQ-51**, to demonstrate compliance with this condition in the Quarterly Operation Reports (**AQ-SC8**).

AQ-42 During periods of cold startup, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO_2) - 90.7 lb/hr, SOx - 5.1 lb/hr, PM10 - 19.0 lb/hr, CO - 1,679.7 lb/hr, or VOC - 266.7 lb/hr, based on one-hour averages. During periods of hot startup, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO_2) - 167.0 lb/hr, SOx - 5.1 lb/hr, PM10 - 19.8 lb/hr, CO - 394.0 lb/hr, or VOC - 98.0 lb/hr, based on one-hour averages. [District Rule 2201]

<u>Verification:</u> The project owner shall submit continuous monitoring data in summary form for pollutants that are continuously monitored, and the most recent source test data (**AQ-51**) for pollutants that are not continuously monitored, or for pollutants where the continuous monitors are not certifiable for the determination of startup emissions, demonstrating compliance with this condition in the Quarterly Operation Reports (**AQ-SC8**).

AQ-43 During periods of shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NOx (as NO_2) - 62.0 lb/hr, SOx - 2.6 lb/hr, PM10 5.0 lb/hr, CO - 126.0 lb/hr, or VOC - 21.1 lb/hr, based on one- hour averages. [District Rule 2201]

<u>Verification:</u> The project owner shall submit continuous monitoring data, in summary form for pollutants that are continuously monitored, and the most recent source test data (**AQ-51**) for pollutants that are not continuously monitored, or for pollutants where the continuous monitors are not certifiable for the determination of shutdown emissions, demonstrating compliance with this condition in the Quarterly Operation Reports (**AQ-SC8**).

AQ-44 Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Hot startup is startup after 24 hours or less downtime and cold startup is startup after greater than 24 hours. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

<u>Verification:</u> No verification necessary.

AQ-45 The duration of each startup and shutdown shall not exceed any of the following: 3 hours for each cold startup, 1 hour for each hot startup, and 0.5 hour for each shutdown. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

<u>Verification:</u> The project owner shall submit startup and shutdown event duration data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-46 The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-47 Daily emissions (target level) from the CTG shall not exceed any of the following limits: NOx (as NO_2) - 910.5 lb/day; VOC - 1,026.3 lb/day; CO -

6,058.2 lb/day; PM10 - 472.0 lb/day; or SOx (as SO_2) - 163.2 lb/day. Daily emissions (upper level) from the CTG shall not exceed any of the following limits: NOx (as NO_2) - 910.5 lb/day; VOC - 1,026.3 lb/day; CO - 6,058.2 lb/day; PM10 - 472.0 lb/day; or SOx (as SO_2) - 163.2 lb/day. [District Rule 2201]

Verification: The project owner shall submit daily emission summaries based on continuous monitoring data, for pollutants that are continuously monitored, and based on the most recent source test data for pollutants that are not continuously monitored demonstrating compliance with this condition in the Quarterly Operation Reports (**AQ-SC8**).

AQ-48 Annual emissions (target level) from the CTG, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following: NOx (as NO_2) - 172,234 lb/year; SOx (as SO_2) - 56,481 lb/year; PM10 - 164,739 lb/year; CO - 261,869 lb/year; or VOC - 53,526 lb/year. Annual emissions (upper level) from the CTG, calculated on a twelve consecutive month rolling basis, shall not exceed any of the following: NOx (as NO_2) - 335,723 lb/year; SOx (as SO_2) - 56,481 lb/year; PM10 - 164,739 lb/year; CO - 311,411 lb/year; or VOC - 67,563 lb/year. [District Rule 2201]

Verification: The project owner shall submit rolling consecutive twelve month emission summaries based on continuous monitoring data, for pollutants that are continuously monitored, and based on the most recent source test data for pollutants that are not continuously monitored demonstrating compliance with this condition in the Quarterly Operation Reports (**AQ-SC8**).

AQ-49 Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

Verification: No verification necessary.

AQ-50 Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

Verification: No verification necessary.

AQ-51 Compliance with the ammonia emission limits shall be demonstrated utilizing one of the following procedures: 1) calculate the daily ammonia emissions using the following equation: (ppmvd @ 15% O_2) = ((a - (b x c/1,000,000)) x (1,000,000 / b)) x d, where a = average ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NOx concentration ppmvd @ 15% O_2 across the catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip; 2.) Utilize another district-approved calculation method using measured surrogate parameters to determine the daily ammonia emissions in ppmvd @ 15% O_2. If this option is chosen, the project owner shall submit a detailed calculation protocol for district approval at least 60 days prior to commencement of operation; 3.) Alternatively, the project owner may utilize a continuous in-stack ammonia monitor to verify compliance with the ammonia emissions limit. If this option is chosen, the project owner shall submit a monitoring plan for district approval at least 60 days prior to commencement of operation. [District Rule 2201]

Verification: The project owner shall, if option 2 above is selected, submit an ammonia emissions calculation method for the APCO to approve and the CPM to review; and if option 3 above is selected, submit an ammonia monitoring plan for district approval at least 60 days prior to commencement of operation.

AQ-52 Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then source testing to measure startup NOx and CO mass emission rates shall be conducted at least once every 12 months. [District Rule 1081]

Verification: The results and field data collected during source tests shall be submitted to the district and CPM within 60 days of testing and according to a pre-approved protocol (**AQ-61**). Testing for startup and shutdown emissions shall be conducted upon initial operation and at least once every seven years.

AQ-53 Hazardous Air Pollutant (HAP) emissions shall not exceed 25 tpy all HAPS or 10 tpy any single HAP. [District Rule 4002]

Verification: The project owner shall submit annual emission summaries based on source test data and estimation methods described in **AQ-54** demonstrating compliance with this condition annually in the fourth quarter Quarterly Operation Report (**AQ-SC8**).

AQ-54 The project owner shall conduct an initial speciated HAPS and total VOC source test for the combustion turbine generator, by district witnessed in situ sampling of exhaust gases by a qualified independent source test firm. The project owner shall correlate the total HAPs emissions rate and the single highest HAP emission rate to the VOC mass emission determined during the speciated HAPs source test. Initial and annual compliance with the HAPs emissions limit (25 tpy all HAPs or 10 tpy any single HAP) shall be demonstrated by the combined VOC emissions rates for the combustion gas turbine determined during initial and annual compliance source testing and the correlation between VOC emissions and HAP(s). [District Rule 4002]

Verification: The results and field data collected during source tests shall be submitted to the district for approval and the CPM for review within 60 days of testing and according to a pre-approved protocol (**AQ-61**).

AQ-55 Source testing to measure the NOx, CO, VOC, and NH_3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM10 emission rate (lb/hr) shall be conducted within 120 days after initial operation and at least once every twelve months thereafter. [District Rules 1081 and 4703 and 40 CFR 60.4400(a)]

Verification: The results and field data collected during source tests shall be submitted to the district and CPM within 60 days of testing and according to a pre-approved protocol (**AQ-61**). Source testing shall be conducted within 120 day of initial operation and at least once every twelve months thereafter.

AQ-56 The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) shall be demonstrated within 60 days after the end of the commissioning period and monitored weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Verification: The fuel source sulfur content data, as required by this condition, shall be provided in the Quarterly Operation Reports (**AQ-SC8**).

AQ-57 The following test methods shall be used: NOx - EPA Method 7E or 20, PM10 - EPA Method 5/202 (front half and back half), CO - EPA Method 10 or 10B, O_2 - EPA Method 3, 3A, or 20, VOC - EPA Method 18 or 25, and ammonia - EPA Method 206. EPA approved alternative test methods as approved by the district may also be used to address the source testing requirements of this permit. The request to utilize EPA approved alternative source testing methods must be submitted in writing and written approval received from the district prior to the submission of the source test plan. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Verification: The project owner shall submit the proposed protocol for the source tests to the district for approval and the CPM for review in accordance with condition **AQ-61**.

AQ-58 HHV and LHV of the fuel shall be determined using ASTM D3588, ASTM 1826, or ASTM 1945. [40 CFR 60.332(a),(b) and District Rule 4703, 6.4.5]

Verification: The project owner shall submit the proposed protocol for the fuel heating value test method to the district for approval and the CPM for review in accordance with condition **AQ-61**.

AQ-59 Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Verification: The fuel source sulfur content testing method demonstrating compliance with this condition shall be provided with the fuel sulfur content data provided for compliance with **AQ-39** and **AQ-56** in the Quarterly Operation Reports (**AQ-SC8**).

AQ-60 The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O_2 analyzer during district inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1080]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-61 Compliance demonstration (source testing) shall be district witnessed or authorized and samples shall be collected by a certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the district. The district must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the district within 60 days thereafter. [District Rule 1081]

Verification: The project owner shall submit the proposed source test plan or protocol for the source tests 15 days prior to the proposed source test date to the district for approval and CPM for review. The project owner shall notify the district and CPM no later than 30 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the district and CPM.

AQ-62 The turbine shall be equipped with a continuous monitoring system to measure and record fuel consumption. [District Rules 2201 and 4703 and 40 CFR 60.4335(b)(1)]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-63 The project owner shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201, and 4703 and 40 CFR 60.4335(b)(1)]

Verification: The project owner shall provide a Continuous Emission Monitoring System (CEMS) protocol demonstrating compliance with the requirements of this condition to the district for approval and the CPM for review at least 60 days prior to installation of the CEMS.

AQ-64 The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the district, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

<u>Verification:</u> The project owner shall provide a Continuous Emission Monitoring System (CEMS) protocol demonstrating compliance with the requirements of this condition to the district for approval and the CPM for review at least 60 days prior to installation of the CEMS.

AQ-65 The NOx, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the district, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

<u>Verification:</u> The project owner shall provide a Continuous Emission Monitoring System (CEMS) protocol demonstrating compliance with the requirements of this condition to the district for approval and the CPM for review at least 60 days prior to installation of the CEMS.

AQ-66 Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The district shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the district. [District Rule 1080]

<u>Verification:</u> The project owner shall submit a CEMS quarterly audit summary demonstrating compliance with this condition in the Quarterly Operation Report (**AQ-SC8**) that occurs after the completion of the quarterly CEMS audit.

AQ-67 The project owner shall perform a relative accuracy test audit (RATA) for the NOx, CO, and O_2 CEMs as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The project owner shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

<u>Verification:</u> The project owner shall submit a CEMS RATA audit summary demonstrating compliance with this condition in the Quarterly Operation Report (**AQ-SC8**) that occurs after the completion of the CEMS RATA audit.

AQ-68 Results of the CEM system shall be averaged over a one hour period for NOx emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

Verification: The project owner shall submit to the district and CPM the report of emission data in the Quarterly Operation Reports (**AQ-SC8**) that follows the definitions of this condition.

AQ-69 Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NOx concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx or O_2 (or both). [40 CFR 60.4380(b)(1)]

Verification: No verification necessary.

AQ-70 Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the district, the ARB, and the EPA. [District Rule 1080]

Verification: The project owner shall submit to the district and CPM emission data in the Quarterly Operation Reports (**AQ-SC8**) that follows the definitions of this condition.

AQ-71 The facility shall install and maintain equipment, facilities, and systems compatible with the district's CEM data polling software system and shall make CEM data available to the district's automated polling system on a daily basis. [District Rule 1080]

Verification: The project owner shall provide a Continuous Emission Monitoring System (CEM) protocol that includes a description of the equipment and systems required by this condition to the district for approval and the CPM for review at least 60 days prior to installation of the CEM.

AQ-72 Upon notice by the district that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the district by a district-approved alternative method. [District Rule 1080]

Verification: The project owner shall provide required non-polled CEM data to the district by a district-approved alternative method and shall provide notification of such how much non-polled data was required to be provided each year in the Annual Compliance Reports.

AQ-73 The project owner shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

Verification: The project owner shall submit to the district a CEM data summary report upon notice from the APCO, and shall provide notification of such reports being submitted to the district in the Annual Compliance Reports.

AQ-74 The project owner shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Verification: The project owner shall submit to the district and CPM the report of CEM operations, emission data, and monitor downtime data in the Quarterly Operation Reports (**AQ-SC8**) that follows the definitions of this condition.

AQ-75 APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-76 The project owner shall notify the district of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the project owner demonstrates to the district's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

Verification: The project owner shall comply with the notification requirements of the district and submit a summary of these notifications demonstrating compliance with this condition in the Annual Compliance Reports.

AQ-77 The district shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Verification: The project owner shall comply with the notification requirements of the district and submit a summary of these notifications demonstrating compliance with this condition in the Annual Compliance Reports.

AQ-78 The project owner shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-79 The project owner shall maintain the following records: quarterly hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

<u>Verification:</u> The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request. Project owner shall provide these data upon request.

AQ-80 All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 2201, and 4703]

<u>Verification:</u> The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-81 Note on NOx, CO, and VOC BACT limits: The project owner proposed to meet emission limits of 4.0 ppmvd-NOx @ 15% O_2, 3.0 ppmvd-CO @ 15% O_2 when firing on hydrogen-rich fuel exclusively and 5.0 ppmvd-CO @ 15% O_2 when firing on fuel containing natural gas, and 1.0 ppmvd-VOC @ 15% O_2 when firing on hydrogen-rich fuel exclusively and 2.0 ppmvd @ 15% O_2 when firing on fuel containing natural (except during startup/shutdown) as these are vendor guaranteed emission rates. The project owner has also agreed to the installation of additional selective catalytic reduction and oxidation catalytic controls on the combustion turbine generator to reduce NOx emissions to a target level of 2.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average) or 2.5 ppmvd@ 15% O_2 (1-hour average) and 3.0 ppmvd-CO @ 15% O_2 when firing on hydrogen-rich fuel exclusively and 4.0 ppmvd-CO @ 15% O_2 when firing on fuel containing natural gas, and 1.0 ppmvd-VOC @ 15% O_2 when firing on hydrogen-rich fuel exclusively and 1.5 ppmvd @ 15% O_2 when firing on fuel containing natural gas (except during startup/shutdown). Target levels have not yet been successfully demonstrated on combustion turbine generators that require burner technology to fire hydrogen-rich fuel. Therefore, if per the district's determination, any of the control technologies do not perform satisfactorily during the initial trial period or experiences repeated failures that are not the result of improper operation, that technology will not be deemed BACT for the particular installation. [District Rule 2201]

<u>Verification:</u> The project owner shall provide CEMS and the latest source test emissions data to demonstrate compliance with this condition in the Quarterly Operation Reports (**AQ-SC8**), and provide the final district BACT determination in the Quarterly Operation Report that follows that determination.

AQ-82 Emissions from the unit in excess of lower targeted NOx, CO, and VOC limits shall not constitute a violation of this permit provided that NOx, CO, and VOC emissions are limited to the lowest achievable emission rate to satisfy BACT. BACT for NOx, CO, and VOC from this unit shall consist of all other emission limitations and operational and design conditions contained in this permit. The final BACT level for NOx, CO, and VOC shall be determined to the satisfaction of the Air Pollution Control Officer in accordance with District Rule 2201 and the district's BACT policy, after 24 months of operating history and a successful compliance source test. [District Rule 2201]

Verification: The project owner shall provide the final district BACT determination in the Quarterly Operation Report (**AQ-SC8**) that follows that determination.

AQ-83 If NOx, CO, and VOC emissions from the unit continue to exceed the lower targeted emissions limits after the 24-month BACT determination period, the project owner shall have 90 days to submit a report containing all monitoring and source test information to the district. The report shall also include an explanation of the steps taken to operate and maintain the combustion turbine generator in such a manner as to minimize any of the emissions exceeding the lower limits and a detailed analysis of all factors that prohibit compliance with the lower emissions limit. In the report, the project owner may also propose a final BACT emission limit for the pollutant exceeding the lower limit for inclusion in this permit. The monitoring data and source test information gathered in accordance with this permit may be shared with other technical experts so their input can be considered when determining the final BACT limits that can be consistently achieved. [District Rule 2201]

Verification: The project owner shall submit, if necessary based on exceeding the lower target emission limits of **AQ-81**, to both the district for approval and the CPM for review the BACT report that provides the monitoring and test data, the operation emissions minimization information, and proposed final BACT emission limits within 90 days of the 24-month BACT determination period.

AQ-84 The district shall establish the final BACT limit for NOx, CO, and VOC, including any applicable averaging periods, and revise the applicable limits contained in the permit within 90 days of the successful completion of the BACT determination period or receipt of the report from the project owner. Within 30 days of receipt of the district's determination, the project owner shall submit an Authority to Construct application to incorporate the revised emissions limit(s). In no case shall the final BACT emission limitation(s) be higher than 4.0 ppmvd-NOx @ 15% O_2, 3.0 ppmvd-CO @ 15% O_2 when firing on hydrogen-rich fuel exclusively and 5.0 ppmvd-CO @ 15% O_2 when firing on fuel containing natural gas, and 1.0 ppmvd-VOC @ 15% O_2 when firing on hydrogen-rich fuel gas exclusively and 2.0 ppmvd @ 15% O_2 when firing on fuel containing natural (except during startup/shutdown). If emissions do not exceed the higher limits, the unit shall be allowed to continue to operate after the BACT evaluation period has ended and before the new Authority to Construct permit has been issued. [District Rule 2201]

Verification: The project owner shall provide the final district BACT determination in the Quarterly Operation Report (**AQ-SC8**) that follows that determination.

AQ-85 If the unit demonstrates reasonably reliable compliance with any of the emissions limit of 2.0 ppmvd-NOx @ 15% O_2 (3-hour rolling average) or 2.5 ppmvd@ 15% O_2 (1-hour average), 1.0 ppmvd-VOC @ 15% O_2 when firing on hydrogen-rich fuel exclusively and 1.5 ppmvd @ 15% O_2 when firing on fuel containing natural gas, or 3.0 ppmvd-CO @ 15% O_2 when firing on hydrogen-rich fuel exclusively and 4.0 ppmvd-CO @ 15% O_2 when firing on fuel containing natural gas (except during startup/shutdown) during the BACT evaluation period, any of those limits shall be deemed BACT for the installation. [District Rule 2201]

Verification: The project owner shall provide the final district BACT determination in the Quarterly Operation Report (**AQ-SC8**) that follows that determination.

EQUIPMENT DESCRIPTION, UNIT S-7616-1-0

Feedstock handling and storage system, including a series of enclosed conveyers, with truck unloading building, feedstock storage silos, crusher, coal/coke feed bin, grinding mill, slurry preparation system, served by dust collection system consisting of hoods and dust collectors.

AQ-86 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-87 Petroleum coke unloading hopper shall be equipped with water/additive misting system, which shall be employed as needed to control dust emissions during unloading. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-88 Operation shall include the following dust collectors serving the following operations: truck unloading (DC-1); coke/coal silos filling (DC-2); mass flow bins (DC-3); coke/coals silos loadout (DC-4); crusher inlet/outlet (DC-5); fluxant bins filling (DC-6). [District Rule 2201]

Verification: No verification necessary.

AQ-89 Truck receiving operation shall be fully enclosed when trucks are in unloading position and spray nozzles shall be automatically activated at or prior to unloading as necessary to prevent visible emissions. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-90 All conveyors and crushers shall be fully enclosed and shall vent only to dust collectors. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-91 All storage silos shall be dust-tight (no visible emissions in excess of 0% opacity) and shall vent only to dust collectors. [District Rules 2201, 4001, and 40 CFR 60.254]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-92 Each dust collector shall be equipped with dust-tight (no visible emissions in excess of 0% opacity) provisions to return collected material to process equipment. [District Rules 2201, 4001, and 40 CFR 60.254]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-93 Each dust collector shall be equipped with operational differential pressure indicators, and during fabric collector operation read in the proper range specified by the manufacturer. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-94 The differential pressure across each compartment of the dust collectors shall be checked and the results recorded quarterly. If the differential pressure across each compartment of the dust collectors is not within the proper range specified by the manufacturer, corrective action is required prior to further operation of the equipment. Corrective action means that the cause of the improper pressure differential is corrected before operation of the equipment is resumed. [District Rule 2201]

Verification: A summary of the pressure gauge monitoring and corrective actions shall be provided in the Annual Compliance Reports.

AQ-95 Each dust collector shall automatically activate whenever process equipment served is activated. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-96 Enclosure dust suppression system water spray nozzles shall automatically operate when truck unloading is occurring. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-97 Material shall not be conveyed or crushed unless ventilation system and dust collector are operating and functioning properly. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-98 The project owner shall maintain daily records of the hours of operation of material unloading at the enclosed truck receiving hoppers and records shall be made available for district inspection upon request. [District Rule 2201]

Verification: The project owner shall make the site available for inspection or records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-99 PM10 emissions shall not exceed any of the following emissions for the following operations: truck unloading: 6.7 lb/day; coke/coal silos filling: 16.8 lb/day; mass flow bins: 7.8 lb/day; coke/coals silos loadout: 5.0 lb/day; crusher inlet/outlet: 4.8 lb/day; fluxant bins filling: 1.3 lb/day. [District Rule 2201]

Verification: The project owner shall provide a summary of operations and maintenance events and annual emissions estimates for the feedstock handling and storage systems that demonstrate compliance with this condition in the Annual Compliance Reports.

AQ-100 PM10 emissions shall not exceed any of the following emissions for the following operations: truck unloading: 470 lb/yr; coke/coal silos filling: 1,190 lb/yr; mass flow bins: 2,524 lb/yr; coke/coal silos loadout: 1,614 lb/yr; crusher inlet/outlet: 1,548 lb/yr; fluxant bins filling: 70 lb/yr. [District Rule 2201]

Verification: The project owner shall provide a summary of operations and maintenance events and annual emissions estimates for the feedstock handling and storage systems that demonstrate compliance with this condition in the Annual Compliance Reports.

AQ-101 The maximum process rates of material on a weight basis shall not exceed any of the following: truck unloading: 18,600 ton/day; coke/coal silos filling: 18,600 ton/day; mass flow bins: 4,080 ton/day; coke/coal silos loadout: 4,080 ton/day; crusher inlet/outlet: 4,080 ton/day; fluxant bins filling: 960 ton/day. [District Rule 2201]

Verification: The project owner shall provide a summary of feedstock handling and storage system process rates that demonstrate compliance with this condition in the Annual Compliance Reports.

AQ-102 The maximum process rates of material on a weight basis shall not exceed any of the following: truck unloading: 1,314,000 ton/yr; coke/coal silos filling: 1,314,000 ton/yr; mass flow bins: 1,314,000 ton/yr; coke/coals silo loadout: 1,314,000 ton/yr; crusher inlet/outlet: 1,314,000 ton/yr; fluxant bins filling: 52,560 ton/yr. [District Rule 2201]

Verification: The project owner shall provide a summary of feedstock handling and storage system process rates that demonstrate compliance with this condition in the Annual Compliance Reports.

AQ-103 Dust collector filters shall be completely inspected annually while not in operation for tears, scuffs, abrasives or holes which might interfere with PM collection efficiency and shall be replaced as needed. [District Rule 2201]

Verification: The project owner shall provide a summary of maintenance events for the feedstock handling and storage systems that demonstrate compliance with this condition in the Annual Compliance Reports.

AQ-104 Visible emissions from the operation shall be checked and record results quarterly. If visible emissions are observed, corrective action is required prior to further loading. Corrective action means that visible emissions are eliminated before next loading event. [District Rule 2201]

Verification: The project owner shall provide a summary of visible emissions monitoring and associated maintenance events for the feedstock handling and storage systems that demonstrate compliance with this condition in the Annual Compliance Reports.

AQ-105 Records of dust collector filter maintenance, inspection, and repairs shall be maintained. The records shall include identification of equipment, date of inspection, corrective action taken, and identification of individual performing inspection. [District Rule 2201]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-106 Particulate matter emissions shall not exceed 0.005 grains/dscf in concentration from this operation. [District Rules 2201, 4001, and 40 CFR 60.254]

Verification: The project owner shall demonstrate compliance with this condition with the source test results provided for compliance with **AQ-107**.

AQ-107 Testing for particulate matter concentration for each dust collector shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 12 calendar months of the date the previous performance test was required to be completed thereafter. If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(1), 40 CFR 60.8]

Verification: The results and field data collected during the particulate matter source tests, conducted using the methods specified in **AQ-108** and in the schedule requirements of this condition, shall be submitted to the district and CPM within 60 days of testing.

AQ-108 Testing for compliance with particulate matter concentration limit shall be conducted using EPA method 5. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. [District Rule 4001 and 40 CFR 60.255(1) and 60.257(5)(i)]

Verification: No verification required.

AQ-109 Testing for the opacity standards for the operations shall be conducted within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility, and within 90 operating days of the date the previous performance test was required to be completed thereafter. If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [District Rule 4001 and 40 CFR 60.255(2), 40 CFR 60.8]

Verification: A summary of all visible emission monitoring records shall be included in the Annual Compliance Reports.

AQ-110 Source testing to determine opacity as required by 40 CFR Part 60, Subpart Y shall be conducted using EPA method 9. [District Rule 4001 and 40 CFR 60.257(a)]

Verification: A summary of all visible emission monitoring records shall be included in the Annual Compliance Reports.

AQ-111 The project owner shall conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [District Rule 4001 and 40 CFR 60.257]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-112 The project owner shall maintain a logbook (written or electronic) with the records specified in 40 CFR Subpart 60.258(a) on-site and make it available upon request. [District Rule 4001 and 40 CFR 60.258]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-113 The project owner shall conduct testing for compliance with the particulate matter concentration limit and particulate matter concentration limit within 60 days after achieving the maximum production rate, not later than 180 days after initial startup of such facility. [District Rule 4001 and 40 CFR 60.258(c), 40 CFR 60.8]

Verification: The results and field data collected during the particulate matter source tests, conducted within the schedule requirements of this condition, shall be submitted to the district and CPM within 60 days of testing.

AQ-114 The project owner shall provide the district at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. [District Rule 4001 and 40 CFR 60.8]

Verification: The project owner shall provide performance test notification to the district and CPM at least 30 days before any performance test.

EQUIPMENT DESCRIPTION, UNIT S-7616-2-0

Gasification system including three GE quench gasifiers (two main and one spare) served by three 18 MMBtu/hr natural gas-fired refractory heaters; syngas scrubbing system; sour shift/low temperature gas cooling (LTGC) system; and a rectisol acid gas removal (AGR) unit.

AQ-115 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-116 Gasifiers shall be fired solely on PUC-quality natural gas. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-117 The total combined hours of operation of the three refractory heaters shall not exceed 3,600 hours per calendar year. [District Rule 2201]

Verification: The project owner shall provide the refractory heater operation data demonstrating compliance with this condition in the Annual Compliance Reports.

AQ-118 No more than two refractory heaters shall be in operation at any one time. [District Rule 2201]

Verification: The project owner shall provide the refractory heater operation data demonstrating compliance with this condition in the Annual Compliance Reports.

AQ-119 Emissions from refractory heaters shall not exceed any of the following emission rates: NOx (as NO_2): 0.24 lb/MMBtu; SOx: 0.0021 lb/MMBtu; PM10: 0.0076 lb/MMBtu; CO:0.035 lb/MMBtu; VOC: 0.068 lb/MMBtu. [District Rule 2201]

Verification: The project owner shall provide a summary of the latest monitored or tested refractory heater emission rates showing compliance with this condition in the Annual Compliance Reports

AQ-120 Compliance testing for the first gasifier preheater tested shall consist of three (3) one-hour tests following EPA. Reference Methods 1-4, 7E and 10. Testing of subsequent gasifier· preheaters shall consist of one (1) twenty-one (21) minute test following EPA Reference Methods 3, 7E, 10, and 19. [District Rule 2201]

Verification: The project owner shall submit the proposed protocol for the source tests and the source tests reports demonstrating compliance with the requirements of this condition to both the district and CPM in accordance with conditions **AQ-124** and **AQ-123**, respectively.

AQ-121 Source testing to measure NOx and CO emissions shall be conducted within 60 days of initial operation under this ATC. [District Rules 2201]

<u>Verification:</u> The initial NOx and CO emissions source tests shall be conducted within 60 days of initial operation and the source test report shall note whether compliance with this condition was achieved.

AQ-122 This unit shall be tested for compliance with the NOx and CO emissions limits at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

<u>Verification:</u> The NOx and CO emissions source tests, after the initial source tests, shall be conducted within the time periods prescribed by this condition and each source test report shall note whether compliance with this condition was achieved.

AQ-123 The results of each source test shall be submitted to the district within 60 days thereafter. [District Rule 1081]

<u>Verification:</u> The project owner shall submit source test results no later than 60 days following the source test date to both the district and CPM.

AQ-124 Source testing shall be conducted using the methods and procedures approved by the district. The district must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

<u>Verification:</u> The project owner shall submit the proposed source test plan or protocol for the source tests 15 days prior to the proposed source test date to the district for approval and CPM for review. The project owner shall notify the district and CPM no later than 30 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the district and CPM.

AQ-125 The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

<u>Verification:</u> The project owner shall submit the proposed protocol for the source tests to both the district and CPM in accordance with condition **AQ-124**.

AQ-126 The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or 10B or ARB Method 100, stack gas oxygen - EPA Method 3 or 3A or ARB Method 100, SOx (lb/MMBtu) - ARB Method 100 or EPA Method 6, 6C or fuel gas sulfur content analysis and EPA Method 19, fuel gas sulfur content - EPA Method 11 or 15, ASTM D3246 or double GC for H_2S and mercaptans performed in a laboratory, fuel gas hhv - ASTM D1826 or D1945 in conjunction with ASTM D3588. [District Rule s 4305, 4306 and 4320]

<u>Verification:</u> The project owner shall submit the proposed protocol for the source tests to both the district and CPM in accordance with condition **AQ-124**.

AQ-127 Fugitive VOC emission rate from the permit unit shall not exceed 73.5 lb/day based on the component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. Components serving the following streams associated with this permit unit shall be subject to a leak detection and repair (LDAR) program: methanol, propylene, H_2S-laden methanol, CO_2-laden methanol, and acid gas. The following control efficiencies in Table 5-2 of the EPA document shall apply to those components under an LDAR program: gas valves: 92%; light liquid valves: 88%; light liquid pump seals: 75%; and connectors: 93%. [District Rule 2201]

Verification: A summary of the calculated fugitive VOC emission rate, using the methods described in this condition, demonstrating compliance with the daily VOC mass emission rate limit in this condition shall be provided in the Annual Compliance Reports.

AQ-128 Fugitive CO emission rate from the permit unit shall not exceed 32.5 lb/day based on the component count, CO percentage in the fluid stream, VOC emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors and the applicable control efficiency for those components subject to a leak detection and repair (LDAR) program. [District Rule 2201]

Verification: A summary of the calculated fugitive CO emission rate, using the methods described in this condition, demonstrating compliance with the daily CO mass emission rate limit in this condition shall be provided in the Annual Compliance Reports.

AQ-129 Emissions attributed to this permit unit shall consist of components serving the following process streams: methanol, syn gas, flash gas/gasification, shifted syn gas, propylene, sour water, H_2S-laden methanol, CO_2-laden methanol, acid gas, and ammonia-laden gas. [District Rule 2201]

Verification: No verification necessary.

AQ-130 The project owner shall maintain with the permit an accurate fugitive component count and the resulting emissions calculated using above specified leak rates and control efficiencies. [District Rule 2201]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-131 The VOC content of the gas in the following streams shall not exceed 10% by weight: syn gas, flash gas/gasification, shifted syn gas, and sour water. [District Rule 2201]

Verification: The project owner shall sample the VOC content of the sulfur and tail gas treatment unit process gases, in the frequency required by **AQ-132** and using the methods specified in **AQ-133**, that demonstrate compliance with this condition; and project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-132 The project owner shall conduct quarterly gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. If gas samples are equal to or less than 10% VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201]

Verification: A summary of gas VOC content sampling conducted to quality for the component count exemption per the requirement of this condition shall be included in the Annual Compliance Report.

AQ-133 VOC content of gas streams shall be determined by ASTM D1945, EPA Method 18 referenced as methane, or equivalent test method with prior district approval. [District Rule 2201]

Verification: A summary of gas VOC content sampling conducted to quality for the component count exemption per the requirements of **AQ-132** shall meet the requirement of this condition and shall be included in the Annual Compliance Report.

AQ-134 All VOC sampling connections, open-ended valves, and lines shall be equipped with two closed valves or be sealed with blind flanges, caps, or threaded plugs except during actual use. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-135 The project owner shall maintain records of the VOC content test results for a period of five years and make such records available for inspection upon request. [District Rule 1070]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-136 For the components serving the methanol, propylene, H_2S-laden methanol, and the CO_2-laden methanol streams, except for those components specified in condition AQ-137 below, a component shall be considered leaking if one of more of the conditions specified in Rule 4455 Sections 5.1.4.1 through 5.1.4.4 of the rule exist at the facility. [District Rule 2201]

Verification: The project owner shall provide a summary of the LDAR records for the methanol, propylene, H_2S-laden methanol, and the CO_2-laden methanol streams in the Annual Compliance Report, and shall make the site available for inspection of the LDAR program records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-137 For valves and connectors serving the methanol, propylene, H_2S-laden methanol, and the CO_2-laden methanol streams, a leak shall be defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21. For pump and compressor seals serving the methanol, propylene, H_2S-laden methanol, and the CO_2-laden methanol streams, a leak shall be defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21. [District Rule 2201]

Verification: The project owner shall provide a summary of the LDAR records for the methanol, propylene, H_2S-laden methanol, and the CO_2-laden methanol streams in the Annual Compliance Report, and shall make the site available for inspection of the LDAR program records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-138 All records required by this permit shall be retained for a period of at least 5 years and shall be made available to the district, ARB, and U.S. EPA upon request. [District Rules 1070 and 2201]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

EQUIPMENT DESCRIPTION, UNIT S-7616-5-0

Sulfur recovery system consisting of sulfur recovery unit (SRU), a, tail gas treating unit (TGTU), and a 10 MMBtu/hr natural gas-fired tail gas thermal oxidizer, and miscellaneous tanks, compressors, pumps, condensers, heat exchangers, and piping.

AQ-139 Sulfur recovery unit shall include two Claus converters, two reheaters, three sulfur condensers, waste gas boiler, reaction furnace, oxygen preheater, main burner, acid gas preheater, acid gas wash drum, acid gas wash drum pumps, sour water stripper (SWS) acid gas knockout drum, SWS acid gas preheater, SWS acid gas drum pumps, combustion air blower, and piping. [District Rule 2201]

Verification: No verification necessary

AQ-140 Tail gas treating unit (TGTU) shall include a tail gas heater, tail gas trim heater, hydrogenation reactor, reactor effluent cooler, contact condenser/desuperheater, desuperheater pumps, contact condenser cooler, TGTU absorber, TGTU absorber water wash pumps, TGTU rich amine pump, lean amine trim cooler, lean amine air cooler, lean amine pumps, lean/rich amine exchanger, regenerator, regenerator overhead condenser, overhead accumulator, regenerator reflux pumps, and regenerator reboiler. [District Rule 2201]

Verification: No verification necessary.

AQ-141 Operation shall include continuously recording H_2S monitor for incinerator inlet (on the TGTU absorber overhead) and incinerator with continuously recording SO_2 and O_2 monitors. [District Rule 2201]

Verification: The project owner shall make the site available for inspection of monitoring records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-142 Exhaust stack shall be equipped with adequate provisions facilitating the collection of samples consistent with EPA test methods. [District Rule 1080]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-143 Incinerator firebox temperature shall be maintained above 1200 °F. [District Rule 2201]

Verification: The project owner shall maintain a working firebox temperature monitoring and recording device and shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-144 Sulfur production shall not exceed 180 short tons/day. [District Rule 2201]

Verification: The project owner shall maintain sulfur production data demonstrating compliance with this condition at the site and shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-145 Shutdown is defined as the period beginning with the termination of acid gas feed and the initiation of fuel feed (for the purpose of heat stripping sulfur from the internal surfaces of the SRU). [District Rule 2201]

Verification: No verification necessary.

AQ-146 Warm standby is defined as the period between shutdown and startup when the SRU feed is solely natural gas. [District Rule 2201]

Verification: No verification necessary.

AQ-147 Startup is defined as the period beginning with the introduction (or increased utilization) of natural to the SRU to raise the temperature of the catalytic reactors to operating temperature (approximately 350 degrees F). Startup ends when the concentration of H_2S in the TGTU absorber offgas does not exceed 10 ppmv (moving three hour average). [District Rule 2201]

Verification: No verification necessary.

AQ-148 Except during shutdown, warm standby, startup, and breakdown (as defined in Rule 1100) conditions, concentration of H_2S in the TGTU absorber offgas shall not exceed 10 ppmv H_2S (moving 3 hour average). [District Rule 2201]

Verification: The project owner shall provide a summary of the H_2S monitoring results that demonstrate compliance with this condition in the Annual Compliance Reports, and shall make the site available for inspection of equipment and records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-149 The project owner shall, at all times including periods of startup, shutdown, and malfunction, maintain and operate the SRU and associated control equipment in a manner consistent with good air pollution control practice for minimizing emissions. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request

AQ-150 In case of any exceedance of any H_2S or SOx (as SO_2) emission limit or any malfunction, the project owner shall begin actions to minimize emissions exceedance or amount of sour gas flared, by removing high sulfur feed stocks and reducing unit rates, or by other means approved by the district. [District Rule 2201]

Verification: The project owner shall provide a summary of actions taken to minimize H_2S and SO_2 emission exceedances or correct equipment malfunctions as required by this condition in the Annual Compliance Reports, and shall make the site available for inspection of equipment and records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-151 Emission rates from the tail gas thermal oxidizer shall not exceed the following: NOx: 0.24 lb/MMBtu; CO: 0.20 lb/MMBtu; VOC: 0.0055 lb/MMBtu; PM10: 0.0076 lb/MMBtu. [District Rule 2201]

Verification: The project owner shall provide a summary of the latest monitored or tested thermal oxidizer emission rates showing compliance with this condition in the Annual Compliance Reports.

AQ-152 SOx (as SO_2) emissions from the tail gas thermal oxidizer shall not exceed 0.0204 MMBtu/hr for the disposal of SRU startup gas nor 2 lb/hr for the disposal of the process vent gas. [District Rule 2201]

Verification: The project owner shall provide a summary of the tail gas thermal oxidizer SO_2 continuous monitoring results that demonstrates compliance with the limits of this condition in the Annual Compliance Reports.

AQ-153 During SRU shutdown, SRU tail gas shall be directed to the TGTU provided the O_2 content of the SRU tail gas is less than or equal to 0.5% by weight as measured with portable O_2 analyzer or equivalent CO value as measured by the CO/CO_2 analyzer. During such periods TGTU tail gas shall be directed to the amine system. During the final 12 hours of SRU shutdown, the SRU tail gas may bypass the TGTU and be introduced directly to the incinerator. [District Rule 2201]

Verification: The project owner shall provide records identifying how compliance with this condition was achieved during each SRU shutdown in the Annual Compliance Reports.

AQ-154 During SRU warm standby, SRU tail gas may bypass the TGTU and be introduced directly to the incinerator. [District Rule 2201]

Verification: The project owner shall provide records identifying the path of the SRU tail gas during SRU warm standby to demonstrate compliance with this condition in the Annual Compliance Reports.

AQ-155 During SRU startup (after being completely down), SRU tail gas may bypass the TGTU and be introduced directly to the incinerator provided the O_2 content of the SRU tail is greater than 0.5% by volume as measured with portable O_2 analyzer or equivalent CO value as measured by the CO/CO_2 analyzer. The duration in which the TGTU is bypassed shall not exceed 36 hours. [District Rule 2201]

Verification: The project owner shall provide records identifying how compliance with this condition was achieved during each SRU startup in the Annual Compliance Reports.

AQ-156 During SRU startup (after being in warm standby), SRU tail gas shall be directed to the TGTU. Within 24 hours of directing the SRU tail gas to the TGTU, the TGTU absorber offgas H_2S content shall not exceed 10 ppmv (three hour rolling average). [District Rule 2201]

Verification: The project owner shall provide records, including SO_2 continuous monitoring results, identifying how compliance with this condition was achieved during each SRU startup in the Annual Compliance Reports.

AQ-157 Emissions for this unit shall be calculated using the arithmetic mean, pursuant to District Rule 1081(amended December 16, 1993), of 3 thirty-minute test runs for NOx and CO. [District Rule 2201]

Verification: The project owner shall provide this unit's emission estimates using the methods required in this condition in the Annual Compliance Reports.

AQ-158 All required source testing shall conform to the compliance testing procedures described in District Rule 1081(Last Amended December 19, 1993). [District Rule 1081]

Verification: The project owner shall submit the proposed source test plan or protocol for the source tests 15 days prior to the proposed source test date to the district for approval and CPM for review. The project owner shall notify the district and CPM no later than 30 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the district and CPM.

AQ-159 Fugitive VOC emission rate from the permit unit shall not exceed 34.2 lb/day based on the component count and emission factors from EPA document Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors. [District Rule 2201]

Verification: A summary of the calculated fugitive VOC emission rate, using the methods described in this condition, demonstrating compliance with the daily VOC mass emission rate limit in this condition shall be provided in the Annual Compliance Reports.

AQ-160 Fugitive CO emission rate from the permit unit shall not exceed 0.2 lb/day based on the component count, CO percentage in the fluid stream, VOC emission factors from Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017), Table 2-1, SOCMI Average Emissions Factors. [District Rule 2201]

Verification: A summary of the calculated fugitive CO emission rate, using the methods described in this condition, demonstrating compliance with the daily CO mass emission rate limit in this condition shall be provided in the Annual Compliance Reports.

AQ-161 Emissions attributed to this permit unit shall consist of components serving the following process streams: sulfur, tail gas treatment unit process, and tail gas treatment unit amine. [District Rule 2201]

Verification: No verification necessary.

AQ-162 The project owner shall maintain with the permit an accurate fugitive component count and the resulting emissions calculated using above specified leak rates and control efficiencies. [District Rule 2201]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-163 The VOC content of the gas in the following streams shall not exceed 10% by weight: sulfur and tail gas treatment unit process. [District Rule 2201]

Verification: The project owner shall sample the VOC content of the sulfur and tail gas treatment unit process gases, in the frequency required by **AQ-164** and using the methods specified in **AQ-165**, that demonstrate compliance with this condition; and project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-164 The project owner shall conduct quarterly gas sampling to qualify for exemption from fugitive component counts for those components handling fluids with VOC content equal to or less than 10% by weight. If gas samples are equal to or less than 10% VOC by weight for 8 consecutive quarterly samplings, sampling frequency shall only be required annually. [District Rule 2201]

Verification: A summary of gas VOC content sampling conducted to quality for the component count exemption per the requirement of this condition shall be included in the Annual Compliance Report.

AQ-165 VOC content of gas streams shall be determined by ASTM D1945, EPA Method 18 referenced as methane, or equivalent test method with prior district approval. [District Rule 2201]

Verification: A summary of gas VOC content sampling conducted to quality for the component count exemption per the requirements of **AQ-164** shall meet the requirement of this condition and shall be included in the Annual Compliance Report.

AQ-166 All VOC sampling connections, open-ended valves, and lines shall be equipped with two closed valves or be sealed with blind flanges, caps, or threaded plugs except during actual use. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-167 The project owner shall maintain records of the VOC content test results for a period of five years and make such records available for inspection upon request. [District Rule 1070]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-168 For the components serving the sulfur, tail gas treatment unit process, and tail gas treatment unit amine streams, except for those components specified in the condition below, a component shall be considered leaking if one of more of the conditions specified in Rule 4455 Sections 5.1.4.1 through 5.1.4.4 of the rule exist at the facility. [District Rule 2201]

Verification: The project owner shall provide a summary of the LDAR records for the sulfur, tail gas treatment unit process, and tail gas treatment unit amine streams in the Annual Compliance Report, and shall make the site available for inspection of the LDAR program records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-169 For valves and connectors serving the sulfur, tail gas treatment unit process, and tail gas treatment unit amine streams, a leak shall be defined as a reading of methane in excess of 100 ppmv above background when measured per EPA Method 21. For pump and compressor seals serving the sulfur, tail gas treatment unit process, and tail gas treatment unit amine streams, a leak shall be defined as a reading of methane in excess of 500 ppmv above background when measure per EPA Method 21. [District Rule 2201]

Verification: The project owner shall provide a summary of the LDAR records for the sulfur, tail gas treatment unit process, and tail gas treatment unit amine streams in the Annual Compliance Report, and shall make the site available for inspection of the LDAR program records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-170 All records required by this permit shall be retained for a period of at least 5 years and shall be made available to the district, ARB, and U.S. EPA upon request. [District Rules 1070 and 2201]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-171 Copies of all fuel invoices, gas purchase contracts, supplier certifications, and test results to determine compliance with the conditions of this permit shall be maintained. The project owner shall record daily amount and type(s) of fuel(s) combusted and all dates on which unit is fired on any noncertified fuel. [District Rule 2201]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-172 Particulate matter emissions shall not exceed 0.1 grain/dscf, 0.1 grain/dscf calculated to 12% CO_2, nor 10 lb/hr. [District Rules 4201, 3.1 and 4301, 5.1 and 5.2.3]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-173 For the sulfur recovery unit, the project owner shall not discharge or cause the discharge of any gases into the atmosphere in excess of 10 ppm by volume (dry basis) of SO_2 at zero percent excess air. [District Rule 2201]

Verification: The project owner shall provide a summary of the SO_2 monitoring results that demonstrate compliance with this condition in the Annual Compliance Reports, and shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-174 For the sulfur recovery unit, a continuous emissions monitoring system shall be installed, calibrated, operated, and reported. The project owner shall report all 12-hour periods during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system exceeds 10 ppm (dry basis, zero percent excess air). [District Rule 2201]

Verification: The project owner shall provide a sulfur recovery unit Continuous Emission Monitoring System (CEM) protocol to the district for approval the CPM for review at least 60 days prior to installation of the CEM. The project owner shall report SO_2 concentration exceedances to the district as required in this condition and shall provide a summary of such exceedances in the Annual Compliance Report.

AQ-175 The project owner shall determine compliance with the SO_2 and H_2S standard using EPA Method 3, EPA Method 6, and EPA Method 15. [District Rule 2201]

Verification: No verification necessary.

EQUIPMENT DESCRIPTION, UNIT S-7616-3-0, UNIT S-7616-6-0, and UNIT S-7616-7-0

UNIT S-7616-3-0: 1,695 MMBtu/hr elevated flare with 0.5 MMBtu/hr natural gas-fired pilot primarily serving gasification block.

UNIT S-7616-6-0: 36 MMBtu/hr natural gas assist elevated flare with 0.3 MMBtu/hr natural gas fired pilot, serving sulfur recovery unit.

UNIT S-7616-7-0: 150 MMBtu/hr emergency elevated flare with 0.3 MMBtu/hr natural gas-fired pilot primarily serving rectisol acid gas removal unit.

AQ-176 Emissions from the flare shall not exceed any of the following (based on total gas combusted) [District Rule 2201]

S-7616-3-0

PM10: 0.0004 lb/MMBtu; NOx (as NO_2): 0.068 lb/MMBtu; VOC: 0.0004 lb/MMBtu; or CO: 0.37 lb/MMBtu when flaring shifted gas and CO: 2.0 lb/MMBtu when flaring unshifted gas.

S-7616-6-0

PM10: 0.03 lb/MMBtu; NOx (as NO_2): 0.12 lb/MMBtu; VOC: 0.0013 lb/MMBtu; or CO: 0.08 lb/MMBtu.

S-7616-7-0

PM10: 0.03 lb/MMBtu; NOx (as NO_2): 0.12 lb/MMBtu; VOC: 0.0013 lb/MMBtu; or CO: 0.08 lb/MMBtu.

Verification: Records necessary to demonstrate compliance with emission limits contained in this condition will be provided in the Annual Compliance Reports.

AQ-177 A flame shall be present at all times when combustible gases are vented through this flare. [District Rules 2201 and 4311, 5.2]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-178 This flare shall be equipped with an automatic ignition system. [District Rules 2201 and 4311, 5.3]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-179 A flame sensing or heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be operational. [District Rule 4311, 5.4]

Verification: The project owner shall maintain a working flare pilot flame monitoring device and shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-180 90 days prior to installation of the flare, the project owner shall submit a flare minimization plan (FMP) that complies with the requirements of Rule 4311 Section 6.5 to the APCO for approval. [District Rule 4311, 6.5]

Verification: The project owner shall submit the flare minimization plan (FMP) at least 90 days prior to the installation of the flare, and every five years thereafter as required by District Rule 4311, to both the district for approval and the CPM for review.

AQ-181 Copies of approved flare minimization plan pursuant to Rule 4311 Section 6.5 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-182 Copies of compliance determination pursuant to 40 CFR 60.18 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-183 Copies of monitoring data collected pursuant to Rule 4311 Section 5.10 shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-184 Effective on and after July 1, 2011, the project owner shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, whichever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311, 6.2]

Verification: The project owner shall submit the records required in this condition to the district in accordance with the schedule of this condition and shall submit a summary of all flaring events and monitoring records the Annual Compliance Reports.

AQ-185 Effective on and after July 1, 2012, and annually thereafter, the project owner of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Rule 4311 Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. [District Rule 4311, 6.2]

Verification: The project owner shall submit the records required in this condition to the district in accordance with the schedule of this condition and shall submit a summary of all flaring events and monitoring records the Annual Compliance Reports.

AQ-186 Effective on and after July 1, 2012, and annually thereafter, the project owner of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO as specified in Rule 4311 Section 6.2.3 within 30 days following the end of each 12 month period. [District Rule 4311, 6.2]

Verification: The project owner shall submit the records required in this condition to the district in accordance with the schedule of this condition and shall submit a summary of all flaring events and monitoring records the Annual Compliance Reports.

AQ-187 The project owner shall submit a flare minimization plan (FMP) as specified in Rule 4311 Section 6.5 to the APCO for approval. [District Rule 4311, 6.5]

Verification: The project owner shall submit the flare minimization plan (FMP) at least 90 days prior to the installation of the flare, and every five years thereafter as required by District Rule 4311, to both the district for approval and the CPM for review.

AQ-188 All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for district inspection upon request. [District Rule 1070]

Verification: The project owner shall make the site records available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

EQUIPMENT DESCRIPTION, UNIT S-7616-3-0

UNIT S-7616-3-0: 1,695 MMBtu/hr elevated flare with 0.5 MMBtu/hr natural gas-fired pilot primarily serving gasification block.

AQ-189 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-190 Flare shall be equipped with flare gas volume flowmeter. [District Rule 2201]

Verification: The project owner shall provide the specifications of the flared gas flowmeter to the district for approval and CPM for review at least 30 days before installation of the flare, and shall make the site available for inspection of equipment and records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-191 Maximum amount of gas combusted in the flare shall not exceed 91,500 MMBtu/day of unshifted gas nor 105,400 MMBtu/day of shifted gas. The project owner shall maintain records of amount of gas combusted, gas type, and reason for flaring event. [District Rule 2201]

Verification: A summary of all flaring events and monitoring records demonstrating compliance with this condition shall be included in the Annual Compliance Reports.

AQ-192 SOx emissions (as SO_2) shall not exceed 113.9 lb/day. [District Rule 2201]

Verification: Records necessary to demonstrate compliance with emission limits contained in this condition will be provided in the Annual Compliance Reports.

AQ-193 The sulfur content of the gas flared shall be limited 5 ppmv, except during combustion turbine generator washes, which will be limited to no more than 5 ppmv. [District Rule 2201]

Verification: Records necessary to demonstrate compliance with flare gas sulfur concentration limits contained in this condition will be provided in the Annual Compliance Reports.

AQ-194 The project owner shall record the sulfur content and the quantity of gas flared and shall demonstrate compliance with the SOx emission limit. [District Rule 2201]

Verification: The project owner shall provide a flared gas sulfur content monitoring plan to the district for approval and CPM for review at least 30 days before installation of the flare, and shall make the site available for inspection of equipment and records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-195 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than five minutes in any two hours which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rule 4101 and 40 CFR 60.18]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-196 A trained observer, as defined in EPA Method 22, shall check visible emissions at least once annually for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rules 4311]

Verification: A summary of all flaring events and visible emission monitoring records demonstrating compliance with this condition shall be included in the Annual Compliance Reports.

AQ-197 Flare pilot shall be fired solely on PUC quality natural gas. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-198 Flare gas pressure shall not be less than 5 psig when incinerating combustible gasses. [District Rule 4311, 5.6]

Verification: The project owner shall maintain a working flare gas pressure gauge and shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-199 Effective on and after July 1, 2011, pursuant to Rule 4311 Section 6.6, the project owner shall monitor vent gas composition using one the methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate. [District Rule 4311, 6.6]

Verification: A summary of all flaring events and monitoring records required shall be included in the Annual Compliance Reports.

AQ-200 Effective on and after July 1, 2011, the project owner shall monitor the volumetric flows of purge and pilot gases with flow measuring devices. [District Rule 4311, Section 6.7]

Verification: A summary of all flaring events and monitoring records required shall be included in the Annual Compliance Reports.

AQ-201 Effective on and after July 1, 2011, if the flare is equipped with a water seal, the project owner shall monitor and record the water level and pressure of the water seal that services each flare daily. [District Rule 4311, Section 6.8]

Verification: A summary of all flaring events and monitoring records required shall be included in the Annual Compliance Reports.

AQ-202 Effective on and after July 1, 2011, periods of flare monitoring system in operation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating. [District Rule 4311, 6.9]

Verification: The project owner shall provide flare monitoring system records to the district as required by this conditions and shall provide a summary of the flare monitoring records demonstrating compliance with this condition each year in the Annual Compliance Report.

AQ-203 Effective on and after July 1, 2011, during periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, the project owner responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices. [District Rule 4311, 6.9]

Verification: The project owner shall monitor the flare as necessary to comply with this condition and shall provide a summary of the flare monitoring records demonstrating compliance with this condition each year in the Annual Compliance Report.

AQ-204 Effective on and after July 1, 2011, the project owner shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure. [District Rule 4311, 6.9]

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-205 Effective on and after July 1, 2011, all in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages. [District Rule 4311, 6.9]

Verification: A summary of all flaring events and monitoring records required shall be included in the Annual Compliance Report, and the project owner shall make the site available for inspection of equipment and records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

EQUIPMENT DESCRIPTION, UNIT S-7616-6-0

UNIT S-7616-6-0: 36 MMBtu/hr natural gas assist elevated flare with 0.3 MMBtu/hr natural gas fired pilot, serving sulfur recovery unit.

AQ-206 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-207 Flare shall be equipped with flare gas volume flowmeter. [District Rule 2201]

Verification: The project owner shall provide the specifications of the flared gas flowmeter to the district for approval and CPM for review at least 30 days before installation of the flare, and shall make the site available for inspection of equipment and records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-208 Total flaring shall be limited to 40 hr/yr. [District Rule 2201]

Verification: A summary of all flaring events and monitoring records demonstrating compliance with this condition shall be included in the Annual Compliance Report.

AQ-209 SOx emissions (as SO_2) shall not exceed 18.4 lb/hr. [District Rule 2201]

Verification: Records necessary to demonstrate compliance with emission limits contained in this condition will be provided in the Annual Compliance Reports.

AQ-210 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than five minutes in any two hours which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rule 4101 and 40 CFR 60.18]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-211 A trained observer, as defined in EPA Method 22, shall check visible emissions at least once annually for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rule 4311]

Verification: A summary of all flaring events and visible emission monitoring records demonstrating compliance with this condition shall be included in the Annual Compliance Reports.

AQ-212 Flare pilot shall be fired solely on PUC quality natural gas. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-213 Flare gas pressure shall not be less than 5 psig when incinerating combustible gasses. [District Rule 4311, 5.6]

Verification: The project owner shall maintain a working flare gas pressure gauge and shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-214 Flare shall be operated with a flame present at all times, and kept in operation when emissions may be vented to it. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. [District Rule 4001, 4311]

Verification: The project owner shall maintain a working flare pilot flame monitoring device and shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-215 The flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311, 5.2 and 40CFR 60.18(c)(2)]

Verification: A summary of all flaring events and monitoring records demonstrating compliance with this condition shall be included in the Annual Compliance Report.

AQ-216 90 days prior to installation, the project owner shall demonstrate to the district how compliance with 40 CFR 60.18 (c)(3) shall be satisfied. Compliance with either subparts (c)(3)(i), or (c)(3)(ii) and (c)(4) shall be demonstrated to the district. [40 CFR 60.18 (c)(3)]

Verification: The project owner shall submit a report, to the district for approval and the CPM for review, demonstrating how compliance with 40 CFR Part 60 requirements, as applicable, that are described in Conditions **AQ-216** through **AQ-221** shall be satisfied at least 30 days prior to the installation of the flare.

AQ-217 If the project owner opts to comply with 40 CFR 60.16 (c)(3)(i), a non-assisted flare shall have a diameter of 3 inches or greater, have a minimum hydrogen content of 8.0% by volume, and be designed for and operated with an exit velocity less than 122 ft/sec and less than the velocity Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (c)(3)(i)(A). [40 CFR 60.18]

Verification: The project owner shall provide, to the district for approval and the CPM for review, flare design specifications that demonstrate compliance with this condition, if applicable, at least 30 days prior to installation of the flare.

AQ-218 If the project owner opts to comply with 40 CFR 60.16 (c)(3)(ii) and (c)(4), the heating value of the gas combusted in the flare shall be at least 200 Btu/scf. [District Rule 4311 and 40 CFR 60.18]

Verification: The project owner shall provide, to the district for approval and the CPM for review, flare design specifications that demonstrate compliance with this condition, if applicable, at least 30 days prior to installation of the flare.

AQ-219 If the project owner opts to comply with 40 CFR 60.16 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity equal to or greater than 60 ft/sec, but less than 400 ft/sec, if the net heating value of the gas being combusted is greater than 1,000 Btu/scf. [40 CFR 60.18]

Verification: The project owner shall provide, to the district for approval and the CPM for review, flare design specifications that demonstrate compliance with this condition, if applicable, at least 30 days prior to installation of the flare.

AQ-220 If the project owner opts to comply with 40 CFR 60.16 (c)(3)(ii) and (c)(4), non-assisted flares shall be operated with an exit velocity less than 60 ft/sec, except as provided in 40 CFR 60.18 (c)(4)(ii) and (iii). [40 CFR 60.18]

Verification: The project owner shall provide, to the district for approval and the CPM for review, flare design specifications that demonstrate compliance with this condition, if applicable, at least 30 days prior to installation of the flare.

AQ-221 If the project owner opts to comply with 40 CFR 60.16 (c)(3)(ii) and (c)(4), non-assisted flares may be operated with an exit velocity less than the velocity Vmax, as determined by the methods specified in 40 CFR 60.18 (f)(5), and less than 400 ft/sec. [40 CFR 60.18]

Verification: The project owner shall provide, to the district for approval and the CPM for review, flare design specifications that demonstrate compliance with this condition, if applicable, at least 30 days prior to installation of the flare.

AQ-222 The net heating value of the gas being combusted in the flare shall be calculated pursuant to 40 CFR 60.18(f)(3) or by using EPA Method 18, ASTM D1946, and ASTM D2382 if published values are not available or cannot be calculated. [40 CFR 60.18]

Verification: The flaring records provided in the Annual Compliance Reports shall identify the heating value calculation used in compliance with the requirements of this condition.

AQ-223 The flare shall be inspected during operation for visible emissions, using EPA Method 22. If visible emissions are observed, corrective action shall be taken.

If visible emissions cannot be eliminated, an EPA Method 9 test shall be conducted within 72 hours. [District Rule 2201 and 40 CFR 60.18]

Verification: A summary of all flaring events and visible emission monitoring records demonstrating compliance with this condition shall be included in the Annual Compliance Reports.

AQ-224 The outlet shall be equipped with an automatic ignition system, or, shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311, 5.3 and 40CFR 60.18]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-225 Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated. [District Rule 4311, 5.4 and 40CFR 60.18]

Verification: The project owner shall maintain a working flare pilot flame monitoring device and shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-226 The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18]

Verification: A summary of all flaring events and monitoring records demonstrating compliance with this condition shall be included in the Annual Compliance Reports.

AQ-227 Upon request, the project owner shall make available to the APCO the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18. [District Rule 4311, 6.1]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-228 Semi-annual reports of all periods without the presence of a flare pilot flame shall be furnished to the District Compliance Division and EPA. [District Rule 4001 and 40CFR 60.115b(d)(3)]

Verification: The project owner shall submit the records required in this condition to the district in accordance with the schedule of this condition and shall submit a summary of all flaring events and monitoring records the Annual Compliance Reports.

AQ-229 The project owner shall keep accurate daily records of the amount of gas combusted in the flare, hours of operation, the sulfur content and heat content of the gas combusted, and records demonstrating compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). The project owner shall keep these records for a period of at least five years and shall make such records available for district inspection upon request. [District Rules 2201 and 4311]

Verification: The project owner shall make the site available for inspection of records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

EQUIPMENT DESCRIPTION, UNIT S-7616-7-0

UNIT S-7616-7-0: 150 MMBtu/hr emergency elevated flare with 0.3 MMBtu/hr natural gas-fired pilot primarily serving rectisol acid gas removal unit.

AQ-230 Flare pilot shall be fired solely on PUC quality natural gas. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-231 This flare shall be operated solely for emergency situations. [District Rule 2201]

Verification: The project owner shall provide a summary of all flaring events and monitoring records demonstrating compliance with this condition shall be included in the Annual Compliance Report.

AQ-232 A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of gas combusted in the unit shall be installed, utilized and maintained. [District Rule 2201]

Verification: The project owner shall provide the specifications of the flared gas flowmeter to the district for approval and CPM for review at least 30 days before installation of the flare, and shall make the site available for inspection of equipment and records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-233 Records of the duration of flare operation, amount of gas burned, and the nature of the emergency situation for flare used during an emergency situation shall be made readily available to the APCO, ARB, and EPA upon request for a minimum of 5 years. [District Rule 4311, 6.1]

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-234 The project owner shall notify the district of any emergency use of the flare within one hour after confirmation that an actual flaring event has occurred, unless the project owner demonstrates to the district's satisfaction that a longer notification period was necessary. However, in the event that confirmation of an actual flaring event cannot be made, then the project owner shall notify the district no more than 3 hours after an alarm indicates that a flaring event may have occurred, unless the project owner demonstrates to the district's satisfaction that a longer notification period was necessary. [District Rule 1070]

Verification: The project owner shall provide notification of emergency flare use to the district as required in this condition and a summary of all flaring events and monitoring records demonstrating compliance with this condition shall be included in the Annual Compliance Report.

AQ-235 The project owner shall report to the district in writing within ten days following the emergency use of the flare. The report shall include 1) a statement that the failure or malfunction has been corrected, the date corrected, and proof of correction; 2) a specific statement of the reason or cause for the occurrence; 3) a description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future; and 4) an estimate of the emissions caused by the emergency use, specifically including duration of flare operation and amount of gas burned. [District Rules 1070 and 4311]

Verification: The project owner shall submit the written report to the district within 10 days of the emergency use of the flare as required by this condition, and shall provide copies of these reports in the Annual Compliance Reports.

EQUIPMENT DESCRIPTION, UNIT S-7616-8-0

CO2 recovery (capture, compression, and transportation) and vent system, serving release a stream consisting of CO2 and other pollutants from the acid gas removal unit and tail gas treatment unit.

AQ-236 Maximum flowrate of vent stream shall not exceed 656,000 lb/hr. [District Rule 2201]

Verification: The project owner shall provide a summary of the hourly flowrates for each CO_2 venting event in the Annual Compliance Reports.

AQ-237 Venting shall only be allowed when transportation system is unavailable due to upset conditions, and such conditions shall not exceed 504 hours per rolling 12-month period. [District Rule 2201]

Verification: A summary of each CO_2 venting event, including the reason for venting demonstrating compliance with this condition, shall be provided in the Annual Compliance Reports.

AQ-238 Vent stream concentration shall not exceed 1,000 ppm-CO, 40 ppm-VOC, nor 10 ppm-H_2S. [District Rule 2201]

Verification: A summary of each CO_2 venting event, including an estimate of the pollutant concentrations demonstrating compliance with this condition, shall be provided in the Annual Compliance Report.

AQ-239 Emission rates from the vent stream shall not exceed 232.7 lb-VOC/day nor 10,180.8 lb-CO/day. [District Rule 2201]

Verification: A summary of each CO_2 venting event, including an estimate of the pollutant mass emission rates demonstrating compliance with this condition, shall be provided in the Annual Compliance Reports.

AQ-240 Vent system shall be equipped with a gas flowmeter. [District Rule 2201]

Verification: Prior to purchasing the vent system flowmeter the project owner shall provide the district and CPM for approval the specifications of the proposed flowmeter.

AQ-241 The project owner shall maintain records of venting events including hourly flowrate of vent stream and reasons for venting event. [District Rule 2201]

Verification: A summary of each CO_2 venting event, including the reason for venting and the hourly flowrate of the vent stream, shall be provided in the Annual Compliance Reports.

AQ-242 The project owner shall monitor the CO, VOC, and H_2S vent gas composition [District Rule 2201]

Verification: Prior to starting operation the project owner shall provide the district and CPM a CO, VOC, and H2S monitoring plan for approval.

AQ-243 Period of venting shall be reported to the district by the following working day, including the duration of the venting event and the vent gas composition observed. [District Rule 2201]

Verification: The project owner shall submit the written report of venting events to the district by the following working day as required in this condition, and shall provide a summary of these reports in the Annual Compliance Reports.

EQUIPMENT DESCRIPTION, UNIT S-7616-4-0, UNIT S-7616-11-0 and UNIT S-7616-12-0

UNIT S-7616-4-0: 42,300 gallons per minute multi-cell mechanical-draft cooling tower with high-efficiency drift eliminators, serving gasification process area.

UNIT S-7616-11-0: 40,200 gallons per minute multi-cell mechanical-draft cooling tower with high-efficiency drift eliminators, serving gasification process area.

UNIT S-7616-12-0: 175,000 gallons per minute multi-cell mechanical-draft cooling tower with high-efficiency drift eliminators, serving gasification process area.

AQ-244 The project owner shall submit cooling tower design details including the cooling tower type, drift eliminator design details, and materials of construction to the district at least 90 days before the tower is operated. [District Rule 7012]

Verification: The manufacturer data for cooling tower, including the guarantee data for the drift eliminator, showing compliance with this condition shall be provided to the CPM and the district at least 90 days prior to cooling tower operation.

AQ-245 All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District NSR Rule]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-246 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-247 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-248 Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-249 No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-250 Drift eliminator drift rate shall not exceed 0.0005%. [District Rule 2201]

Verification: The manufacturer guarantee data for the drift eliminator, showing compliance with this condition, shall be provided to the CPM and the district at least 90 days prior to cooling tower operation.

AQ-251 PM10 emission rate from the cooling towers shall not exceed 22.9 lb/day for S-7616-4-0, 21.7 lb/day for S-7616-11-0, and 94.6 lb/day for S-7616-12-0. [District Rule 2201]

Verification: Cooling tower emissions data demonstrating compliance with this condition shall be provided as part of the Annual Compliance Reports.

AQ-252 Compliance with the PM10 daily emission limit shall demonstrated as follows: PM10 lb/day = circulating water recirculation rate x total dissolved solids concentration in the blowdown water x design drift rate. [District Rule 2201]

Verification: The project owner shall follow the calculation requirements of this condition for the emissions calculations submitted in the Annual Compliance Reports.

AQ-253 Compliance with the PM10 emission limit shall be determined by blowdown water sample analysis by independent laboratory within 120 days of initial operation and quarterly thereafter. [District Rule 1081]

Verification: The project owner shall submit the results of blowdown water sample analyses in the next Quarterly Operation Report (**AQ-SC8**) following the test.

EQUIPMENT DESCRIPTION, UNIT S-7616-13-0

142 MMBtu/hr NBC model NS-F-70-Econ natural gas fired auxiliary boiler equipped with Todd combustion low NOx burners and flue gas recirculation (or equivalent).

AQ-254 The project owner shall obtain written district approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the district's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

Verification: The project owner shall submit the written request for the use of equivalent equipment, if necessary, to both the district and CPM for approval in accordance with this condition.

AQ-255 The project owner's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

Verification: The project owner shall submit the written request for the use of equivalent equipment, if necessary, to both the district and CPM for approval in accordance with this condition.

AQ-256 Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

Verification: The project owner shall submit the written request for the use of equivalent equipment, if necessary, to both the district and CPM for approval in accordance with **AQ-254** and **AQ-255**.

AQ-257 No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

Verification: The project owner shall submit the written request for the use of equivalent equipment, if necessary, to both the district and CPM for approval in accordance with **AQ-254** and **AQ-255**.

AQ-258 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-259 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-260 Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-261 The unit shall be fired solely on PUC-quality natural gas. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-262 Duration of startup and shutdown shall not exceed 2 hours each per occurrence. Refractory curing period is defined as a maintenance-based reduced-load period of time during which a unit is brought from a shutdown status to staged rates of firing for the sole purpose of curing new refractory lining of the unit, and shall not exceed 30 hours per occurrence. The project owner shall maintain records of the duration of start-up, shutdown, and refractory curing periods. [District Rules 4305, 4306, and 4320]

Verification: The project owner shall submit refractory curing records demonstrating compliance with the requirements of the this condition in the Monthly Compliance Report for the initial refractory curing and shall submit post commissioning period refractory curing records and start-up and shutdown records demonstrating compliance with the requirements of this condition in the Annual Compliance Reports.

AQ-263 Emissions from this unit, except during startup, shutdown, or refractory curing shall not exceed any of the following limits: NOx (as NO_2): 5 ppmvd @ 3% O_2 or 0.006 lb/MMBtu, SOx (as SO_2): 0.00285 lb/MMBtu, PM10: 0.0076 lb/MMBtu, CO: 50.8 ppmvd @ 3% O_2 or 0.037 lb/MMBtu, or VOC: 0.0040 lb/MMBtu. [District Rules 2201, 4305, 4306 and 4320]

Verification: The project owner shall provide source test or other compliance data confirming that these emission limits are being met in the Annual Compliance Report.

AQ-264 Source testing to measure NOx and CO emissions shall be conducted within 60 days of initial operation under this ATC and whenever flue gas recirculation is changed. [District Rules 2201, 4305, 4306 and 4320]

Verification: The results and field data collected during source tests shall be submitted to the district and CPM within 60 days of testing and according to a pre-approved protocol (**AQ-267**).

AQ-265 This unit shall be tested for compliance with the NOx and CO emissions limits at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

Verification: The results and field data collected during source tests shall be submitted to the district and CPM within 60 days of testing and according to a pre-approved protocol (**AQ-267**).

AQ-266 The results of each source test shall be submitted to the district within 60 days thereafter. [District Rule 1081]

Verification: The project owner shall submit source test results no later than 60 days following the source test date to both the district and CPM.

AQ-267 Source testing shall be conducted using the methods and procedures approved by the district. The district must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

Verification: The project owner shall submit the proposed source test plan or protocol for the source tests 15 days prior to the proposed source test date to both the district for approval and the CPM for review. The project owner shall notify the district and CPM no later than 30 days prior to the proposed source test date and time.

AQ-268 The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

Verification: The project owner shall submit the proposed protocol for the source tests to both the district and CPM in accordance with condition **AQ-267**.

AQ-269 The following test methods shall be used: NOx (ppmv) - EPA Method 7E or ARB Method 100, NOx (lb/MMBtu) - EPA Method 19, CO (ppmv) - EPA Method 10 or 10B or ARB Method 100, stack gas oxygen - EPA Method 3 or 3A or ARB Method 100, SOx (lb/MMBtu) - ARB Method 100 or EPA Method 6, 6C or fuel gas sulfur content analysis and EPA Method 19, fuel gas sulfur content - EPA Method 11 or 15, ASTM D3246 or double GC for H_2S and mercaptans performed in a laboratory, fuel gas hhv - ASTM D1826 or D1945 in conjunction with ASTM D3588. [District Rule s 4305, 4306 and 4320]

Verification: The project owner shall submit the proposed protocol for the source tests to both the district and CPM in accordance with condition **AQ-267**.

AQ-270 The project owner shall monitor and record the stack concentration of NOx, CO, and O_2 at least once every month (in which a source test is not performed) using a portable analyzer that meets district specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305 and 4306]

Verification: The project owner shall make the exhaust gas analyzer records available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-271 If either the NOx or CO concentrations corrected to 3% O_2, as measured by the portable analyzer, exceed the allowable emissions concentration, the project owner shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the project owner shall notify the district within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the project owner may stipulate a violation has occurred, subject to enforcement action. The project owner must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the project owner may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

Verification: The project owner shall provide information regarding gas analyzer based boiler re-tuning events and other actions required to maintain compliance with this condition in the Annual Compliance Report.

AQ-272 All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

Verification: The project owner shall make the exhaust gas analyzer records available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-273 The project owner shall maintain records of: (1) the date and time of NOx, CO, and O_2 measurements, (2) the O_2 concentration in percent by volume and the measured NOx and CO concentrations corrected to 3% O_2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

Verification: The project owner shall make the exhaust gas analyzer records available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-274 For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306, and 4320]

Verification: No verification necessary.

AQ-275 All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for district inspection upon request. [District Rules 1070, 2201, 4305, 4306, and 4320]

Verification: The project owner shall make the site records available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

EQUIPMENT DESCRIPTION, UNIT S-7616-14-0, UNIT S-7616-15-0 and UNIT S-7616-16-0

UNIT S-7616-14-0: 2,922 BHP Cummins Model QSK60-G6 Tier 4 certified diesel-fired emergency standby IC engine powering a 2,000 KW Cummins Model DQKC electric generator, #1 (or equivalent).

UNIT S-7616-15-0: 2,922 BHP Cummins Model QSK60-G6 Tier 4 certified diesel-fired emergency standby IC engine powering a 2,000 KW Cummins Model DQKC electric generator, #2 (or equivalent).

UNIT S-7616-16-0: 556 BHP Cummins Model CFP-15E-F40 Tier 4 certified diesel-fired emergency standby IC engine powering a firewater pump (or equivalent).

AQ-276 The project owner shall obtain written district approval for the use of any equivalent equipment not specifically approved by this Authority to Construct. Approval of the equivalent equipment shall be made only after the district's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

Verification: The project owner shall submit the written request for the use of equivalent equipment, if necessary, to both the district and CPM for approval in accordance with this condition.

AQ-277 The project owner's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2201]

Verification: The project owner shall submit the written request for the use of equivalent equipment, if necessary, to both the district and CPM for approval in accordance with this condition.

AQ-278 Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

Verification: The project owner shall submit the written request for the use of equivalent equipment, if necessary, to both the district and CPM for approval in accordance with **AQ-276** and **AQ-277**.

AQ-279 No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

Verification: The project owner shall submit the written request for the use of equivalent equipment, if necessary, to both the district and CPM for approval in accordance with **AQ-276** and **AQ-277**.

AQ-280 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-281 Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Verification: The project owner shall submit the results of source tests to both the district and CPM.

AQ-282 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-283 The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-284 Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

Verification: The project owner shall submit fuel purchase records that demonstrate compliance with the sulfur content limits of this condition in the Annual Compliance Report

AQ-285 This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

Verification: At least 30 days prior to the installation of the engine, the project owner shall provide the district and the CPM the specification of the hour meter.

AQ-286 An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the project owner. [District Rule 4702]

Verification: No verification necessary.

AQ-287 Emissions from this IC engine shall not exceed any of the following limits [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]:

<u>S-7616-14-0</u>

0.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.3 g-VOC/bhp-hr.

<u>S-7616-15-0</u>

0.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.3 g-VOC/bhp-hr.

<u>S-7616-16-0</u>

1.5 g-NOx/bhp-hr, 2.6 g-CO/bhp-hr, or 0.14 g-VOC/bhp-hr.

<u>Verification:</u> The project owner shall submit the engine specifications at least 30 days prior to purchasing the engines for review and approval demonstrating that the engines meet NSPS and ARB ATCM emission limit requirements at the time of engine purchase and the emission limit requirements of this condition.

AQ-288 Emissions from this IC engine shall not exceed 0.07 g-PM10/bhp-hr for S-7616-14-0 and S-7616-15-0, and 0.01 g-PM10/bhp-hr for S-7616-16-0 based on U.S. EPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

<u>Verification:</u> The project owner shall submit the engine specifications at least 30 days prior to purchasing the engines for review and approval demonstrating that the engines meet NSPS and ARB ATCM emission limit requirements at the time of engine purchase and the emission limit requirements of this condition.

AQ-289 The project owner shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the project owner may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

<u>Verification:</u> The project owner shall make the site and site records available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

AQ-290 All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for district inspection upon request. [District Rule 4702 and 17 CCR 93115]

<u>Verification:</u> The project owner shall make the site records available for inspection by representatives of the district, ARB, U.S. EPA, and the Commission upon request.

EQUIPMENT DESCRIPTION, UNIT S-7616-14-0 and UNIT S-7616-15-0

UNIT S-7616-14-0: 2,922 BHP Cummins Model QSK60-G6 Tier 4 certified diesel-fired emergency standby IC engine powering a 2,000 KW Cummins Model DQKC electric generator, #1 (or equivalent).

UNIT S-7616-15-0: 2,922 BHP Cummins Model QSK60-G6 Tier 4 certified diesel-fired emergency standby IC engine powering a 2,000 KW Cummins Model DQKC electric generator, #2 (or equivalent).

AQ-291 This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

Verification: The project owner shall submit records demonstrating compliance with the engine use limits of this condition in the Annual Compliance Report, including a photograph showing the annual reading of engine hours.

EQUIPMENT DESCRIPTION, UNIT S-7616-16-0

UNIT S-7616-16-0: 556 BHP Cummins Model CFP-15E-F40 Tier 4 certified diesel-fired emergency standby IC engine powering a firewater pump (or equivalent).

AQ-292 This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 100 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

Verification: The project owner shall submit records demonstrating compliance with the engine use limits of this condition in the Annual Compliance Report, including a photograph showing the annual reading of engine hours.

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SJVAPCD 2010c (San Joaquin Valley Air Pollution Control District/ (tn: 57512). Preliminary Determination of Compliance, Hydrogen Energy California Project. Dated 06/21/10. Submitted to CEC/Docket Unit on 06/25/10.

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ACRONYMS

AADT	Annual Average Daily Trip
AAQS	Ambient Air Quality Standard
AER	Actual Emissions Reductions
AERMOD	ARMS/EPA Regulatory Model
AFC	Application for Certification
AGR	Acid Gas Removal
APCO	Air Pollution Control Officer (SJVAPCD)
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMP	Air Quality Management Plan
AQRVs	Air Quality Related Values
ARB	California Air Resources Board
ASTM	American Society for Testing of Materials
ASU	Air Separation Unit
ATC	Authority to Construct
ATCM	Air Toxics Control Measure
BACT	Best Available Control Technology
bhp	Brake Horse Power
BOP	Balance of Plant
Btu	British Thermal Units
CAAQS	California Ambient Air Quality Standards
CAISO	California Independent System Operator
CalEPA	California Environmental Protection Agency
CALPUFF	California Puff Model
CEC	California Energy Commission (or Energy Commission)
CEM	Continuous Emission Monitor
CEQA	California Environmental Quality Act
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO2E	Carbon Dioxide Equivalent
CPM	(CEC) Compliance Project Manager
CTG	Combustion Turbine Generator
dscf	Dry Standard Cubic Foot
dscm	Dry Standard Cubic Meter
EIR	Environmental Impact Reports
EOR	Enhanced Oil Recovery
EPS	Emission Performance Standard
ERC	Emission Reduction Credit
FDOC	Final Determination Of Compliance
FGR	Flue Gas Recirculation
FMP	Flare Minimization Plan
FSA	Final Staff Assessment
GCC	Global Climate Change
GE	General Electric
GHG	Greenhouse Gas
GPM	Gallon Per Minute

gr	Grains (1 gr ≅ 0.0648 grams, 7000 gr = 1 pound)
GWh	Gigawatt-hour
H_2S	Hydrogen Sulfide
HAPs	Hazardous Air Pollutants
HECA	Hydrogen Energy California Project
HEI	Hydrogen Energy International, LLC
HFCs	Hydrofluorocarbons
HHV	Higher Heating Value
hp	Horse Power
HRSG	Heat Recovery Steam Generator
HSC	Health and Safety Code
IEPR	Integrated Energy Policy Report
IGCC	Integrated Gasification Combined Cycle
KW	Kilowatts (1,000 Watts)
LADWP	Los Angeles Depart of Water and Power
LDAR	Leak Detection and Repair
LHV	Lower Heating Value
LORS	Law, Ordinances, Regulations, and Standards
LRAs	Local Reliability Areas
LTGC	Low Temperature Gas Cooling
$\mu g/m^3$	Microgram per cubic meter
mg/m^3	Milligram per cubic meter
MMBtu	Million British Thermal Units
MT	Metric Tonnes
MW	Megawatts (1,000,000 Watts)
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NH_3	Ammonia
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen *or* Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O & M	Operation and Maintenance
O_3	Ozone
OLM	Ozone Limiting Method
OTC	Once-Through Cooling
PDOC	Preliminary Determination Of Compliance
PFC	Perfluorocarbons
PG&E	Pacific Gas & Electric Company
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
ppm	Parts Per Million

ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
ppmw	Parts Per Million by Weight
PSA	Preliminary Staff Assessment (this document)
PSD	Prevention of Significant Deterioration
PTO	Permit to Operate
PUC	California Public Utility Commission
QFER	Quarterly Fuel and Energy Report
RACM	Reasonably Available Control Measure
RACT	Reasonably Available Control Technology
RATA	Relative Accuracy Test Audit
RPS	Renewable Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
scf	Standard Cubic Foot
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
SIP	State Implementation Plan
SJVAB	San Joaquin Valley Air Basin
SJVAPCD	San Joaquin Valley Air Pollution Control District (also district)
SO_2	Sulfur Dioxide
SO_4	Sulfates
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SOx	Oxides of Sulfur
SRU	Sulfur Recovery Unit
STG	Steam Turbine Generator
SWPPP	Storm Water Pollution Prevention Plan
SWRCB	State Water Resource Control Board
SWS	Sour Water Stripper
TCMs	Transportation Control Measures
TDS	Total Dissolved Solids
TFV	Threshold Friction Velocity
TGTU	Tail Gas Treating Unit
TPAs	Transportation Planning Agencies
U.S.EPA	United States Environmental Protection Agency
VDE	Visible Dust Emissions
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compounds
WECC	Western Electricity Coordinating Council

HAZARDOUS MATERIALS MANAGEMENT

Alvin Greenberg, Ph.D. and Rick Tyler

SUMMARY OF CONCLUSIONS

Staff's evaluation of the proposed Hydrogen Energy California (HECA) project, along with staff's proposed mitigation measures, indicates that hazardous materials use at the site would not present a significant impact to the public. With adoption of the proposed conditions of certification, the proposed project will comply with all applicable laws, ordinances, regulations, and standards.

Staff wishes to note that the proposed HECA project is a complex industrial facility similar in scope to a small refinery. The presence of numerous chemical processes -- specifically the larger gasification process and sulfur recovery process that will require large amounts of hazardous materials in closed tanks and piping at elevated temperature and pressure -- pose significant risks if not managed properly. Staff has not encountered such a complex power generation facility in the history of the Energy Commission. In order to properly review the hazardous materials proposed for use at this project, as well as those hazardous materials that will be produced by the project, staff spent considerable time evaluating the entire process and even visited a similar gasification facility in Polk County, Florida. As a result of staff's efforts to understand the process and the risks involved, staff determined that several processes must be managed in greater detail than usual, regardless if the quantities of hazardous materials present are below the federal or state thresholds that would trigger this increased level of management.

Therefore, staff is proposing that the project owner be required to develop a Process Safety Management Plan (PSM Plan, which includes a Hazard and Operability analysis to address several different processes), a Risk Management Plan (RMP, which would include several new Offsite Consequence Analyses), and a Spill Prevention Control and Countermeasures (SPCC) Plan. Staff believes that these plans will identify potential system failures and mitigation to reduce the risk of off-site consequences to the public to less than significant.

INTRODUCTION

The purpose of this hazardous materials management analysis is to determine if the proposed Hydrogen Energy California (HECA) project has the potential to cause significant impacts on the public as a result of the use, handling, storage, or transportation of hazardous materials at the proposed site. If significant adverse impacts on the public are identified, Energy Commission staff must also evaluate the potential for facility design alternatives and additional mitigation measures to reduce those impacts to the extent feasible.

The proposed HECA project would gasify petroleum coke (or blends of petroleum coke and coal, as needed) to produce hydrogen to fuel a combustion turbine operating in combined cycle mode. The gasification block would provide fuel to a 390 megawatt (MW) gross/250 MW net combined cycle power plant providing California with baseload power to the grid. The gasification block would also capture approximately 90% of the carbon as carbon dioxide (CO_2) from the raw syngas (the direct end of the gasification process) at steady-state operation, which will be transported to the custody transfer point at Elk Hills Oil Field for CO_2 injection into the oil-bearing geological zone for enhanced oil recovery (EOR) and sequestration (see PSA Part 2 **Air Quality, Appendix A,**, **Green House Gas,** for further information regarding the sequestration of CO_2).

This analysis does not address the potential exposure of workers to hazardous materials used at the proposed facility. Employers must inform employees of hazards associated with their work and provide them with special protective equipment and training to reduce the potential for health impacts associated with the handling of hazardous materials. The **Worker Safety and Fire Protection** section of this document describes applicable requirements for the protection of workers from these risks.

Aqueous ammonia (19% ammonia in aqueous solution), is the only extremely hazardous material proposed to be either used or stored at the HECA project in quantities exceeding the reportable amounts defined in the California Health and Safety Code, section 25532 (j) (HEI 2008c, Tables 5.12-3 and 5.12-4). Aqueous ammonia will be used to control oxides of nitrogen (NO_x) emissions through selective catalytic reduction. The use of aqueous ammonia significantly reduces the risk that would otherwise be associated with the use of the more hazardous anhydrous form of ammonia. Use of the aqueous form eliminates the high internal energy associated with the anhydrous form, which is stored as a liquefied gas at high pressure. The high internal energy associated with the anhydrous form of ammonia can act as a driving force in an accidental release, which can rapidly introduce large quantities of the material to the ambient air and result in high down-wind concentrations. Spills associated with the aqueous form are much easier to contain than those associated with anhydrous ammonia, and emissions from such spills are limited by the slow mass transfer from the surface of the spilled material.

Other hazardous materials such as mineral and lubricating oils, methanol, syngas, acid gas, sulfuric acid, and welding gasses will be stored and sued or will be generated by the processes of the HECA project. Hazardous materials used during construction would include gasoline, diesel fuel, motor oil, hydraulic fluid, welding gases, lubricants, solvents, paint, and paint thinner. No extremely hazardous materials will be used on site during construction. None of these materials pose significant potential for off-site impacts as a result of the quantities on site, their relative toxicity, their physical state, and/or their environmental mobility. Handling of hazardous materials during construction would comply with all applicable regulations and would be guided by a Hazardous Materials Business Plan (HEI 2008c, Section 5.12.2.1).

Although no natural gas is stored, the project will also involve the handling of large amounts of natural gas. Natural gas poses some risk of both fire and explosion. The proposed HECA project would connect to one of two potential pipeline systems, provided by either Southern California Gas Company or Pacific Gas and Electric (HEI 2008c, Section 2.1.8.2). The HECA project would also require the transportation of aqueous ammonia to the facility. This document addresses all potential impacts associated with the use and handling of hazardous materials.

However, staff wishes to note that other hazardous materials will be generated and stored, albeit temporarily, at this proposed facility, including extremely hazardous materials such as hydrogen sulfide (H_2S). Since H_2S is a by-product of the gasification process and it is removed from the enclosed process system and mostly converted to elemental sulfur (a solid powder with low potential for migration or adverse impacts on people) for sale off-site, staff addresses the emissions of H_2S into the atmosphere due to an accidental release in this section and as fugitive emissions from the process system in the **Public Health** section of this PSA.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws and policies apply to the protection of public health and hazardous materials management. Staff's analysis examines the project's compliance with these requirements.

HAZARDOUS MATERIALS MANAGEMENT Table 1
Laws, Ordinances, Regulations, and Standards

Applicable Law	Description
Federal	
The Superfund Amendments and Reauthorization Act of 1986 (42 USC §9601 et seq.)	Contains the Emergency Planning and Community Right To Know Act (also known as SARA Title III).
The Clean Air Act (CAA) of 1990 (42 USC 7401 et seq. as amended)	Established a nationwide emergency planning and response program and imposed reporting requirements for businesses that store, handle, or produce significant quantities of extremely hazardous materials.
The CAA section on risk management plans (42 USC §112(r)	Requires states to implement a comprehensive system informing local agencies and the public when a significant quantity of such materials is stored or handled at a facility. The requirements of both SARA Title III and the CAA are reflected in the California Health and Safety Code, section 25531, et seq.
49 CFR 172.800	The U.S. Department of Transportation (DOT) requirement that suppliers of hazardous materials prepare and implement security plans.
49 CFR Part 1572, Subparts A and B	Requires suppliers of hazardous materials to ensure that all their hazardous materials drivers are in compliance with personnel background security checks.
The Clean Water Act (CWA) (40 CFR 112)	Aims to prevent the discharge or threat of discharge of oil into navigable waters or adjoining shorelines. Requires a written spill prevention, control, and countermeasures (SPCC) plan to be prepared for facilities that store oil that could leak into navigable waters.
Federal Register (6 CFR Part 27) interim final rule	A regulation of the U.S. Department of Homeland Security that requires facilities that use or store certain hazardous materials to submit information to the department so that a vulnerability assessment can be conducted to determine what certain specified security measures shall be implemented.
State	
Title 8, California	Requires facility owners to develop and implement effective safety

Code of Regulations, section 5189	management plans that ensure that large quantities of hazardous materials are handled safely. While such requirements primarily provide for the protection of workers, they also indirectly improve public safety and are coordinated with the Risk Management Plan (RMP) process.
California Health and Safety Code, section 41700	Requires that "No person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes 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."
California Safe Drinking Water and Toxic Enforcement Act (Proposition 65)	Prevents certain chemicals that cause cancer and reproductive toxicity from being discharged into sources of drinking water.
Hazardous Material Business Plan, Cal HSC Sections 25500 to 25541; 19 CCR Sections 2720 to 2734	Requires the submittal of a chemical inventory and planning and reporting for management of hazardous materials.
Hazardous Substance Information and Training Act, 8 CCR Section 339; Section 3200 et seq., 5139 et seq., and 5160 et seq.	Requires listing and implementation of specified control measures for management of hazardous substances.
California HSC Sections 25270 through 25270.13	Requires the preparation of a Spill Prevention, Control, and Countermeasures (SPCC) Plan if 10,000 gallons or more of petroleum is stored on-site. The above regulations would also require the immediate reporting of a spill or release of 42 gallons or more to the California Office of Emergency Services and the Certified Unified Program Authority (CUPA).
Process Safety Management: Title 8 CCR Section 5189	Requires facility owners to develop and implement effective process safety management plans when toxic, reactive, flammable, or explosive chemicals are maintained on site in quantities that exceed regulatory thresholds.
Local	
County of Kern EHSD	Requires new/modified businesses to complete an HMBP prior to final plan/permit approval.

The Certified Unified Program Agency (CUPA) with the responsibility to review Risk Management Plans (RMPs) and Hazardous Materials Business Plans (HMBPs) is the Kern County Environmental Health Services Department (EHSD) (HEI 2008c, Section 5.12.6.3). With regard to seismic safety issues, the site is located in Seismic Risk Zone 4. Construction and design of buildings and vessels storing hazardous materials will meet the seismic requirements of the 2007 California Building Code and the American Society of Civil Engineers standards ASCE 7-05 (HEI 2008c, Section 2.7.1).

SETTING

Several factors associated with the area in which a project is to be located affect the potential for an accidental release of a hazardous material that could cause public health impacts. These include:

- local meteorology;
- terrain characteristics; and
- location of population centers and sensitive receptors relative to the project.

METEOROLOGICAL CONDITIONS

Meteorological conditions, including wind speed, wind direction, and air temperature, affect both the extent to which accidentally released hazardous materials would be dispersed into the air and the direction in which they would be transported. This affects the potential magnitude and extent of public exposure to such materials, as well as their associated health risks. When wind speeds are low and the atmosphere stable, dispersion is severely reduced but can lead to increased localized public exposure.

Recorded wind speeds and directions are described in the **Air Quality** section (5.1.1.1) and **Appendix C** of the Application for Certification (AFC) (HEI 2008c). Staff agrees with the applicant that use of F stability (stagnated air, very little mixing), wind speed of 1.5 meters per second, and an ambient temperature of 115°F are appropriate for conducting the worst-case off-site consequence analyses (HEI 2008c, Appendix L).

TERRAIN CHARACTERISTICS

The location of elevated terrain is often an important factor in assessing potential exposure. An emission plume resulting from an accidental release may impact high elevations before impacting lower elevations. The site topography is predominantly flat (about 282 to 291 feet above mean sea level), with elevated terrain existing about 2 miles south and southwest (HEI 2008c, Section 5.12 and Figure 2-7).

LOCATION OF EXPOSED POPULATIONS AND SENSITIVE RECEPTORS

The general population includes many sensitive subgroups that may be at greater risk from exposure to emitted pollutants. These sensitive subgroups include the very young, the elderly, and those with existing illnesses. In addition, the location of the population in the area surrounding a project site may have a major bearing on health risk. Sensitive receptors and residences in the project vicinity are shown in Figure 5.6-1 of the AFC (HEI 2008c). The nearest sensitive receptor is the Tule Elk State Natural Reserve, which begins about 1,700 feet east of the project site. The only other sensitive receptor within a 6-mile radius of the project site is the Elk Hills Elementary School, located approximately 1.3 miles southeast of the site boundary (HEI 2008c, Section 5.6.1). The nearest residences are located approximately 370 feet northwest of the project site and several hundred feet east of the project site (at the intersection of Tupman Rd and Station Rd). Additional residences are located approximately 1,400 feet to the east and 3,300 feet to the southeast of the project site. The unincorporated community of Tupman is about 1.5 miles southeast of the project site. (HEI 2008c, Sections 5.6 &

5.6.1). The applicant has stated that it will purchase the nearest residence (370 feet from the facility fenceline) and that purchase will be required by proposed Condition of Certification **HAZ-9**. Staff believes that this residence's proximity to the facility would place any resident at a significant risk of harm if allowed to continue to reside at that location. Purchase of the property, removal of the present residents, and a prohibition of future residents would remove that risk.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff reviewed and assessed the potential for the transportation, handling, and use of hazardous materials to impact the surrounding community. All chemicals and natural gas were evaluated. Staff's analysis addresses the potential impacts on all members of the population including the young, the elderly, and people with existing medical conditions that may make them more sensitive to the adverse effects of hazardous materials. In order to accomplish this goal, staff utilized the most current public health exposure levels (both acute and chronic) that are established to protect the public from the effects of an accidental chemical release.

In order to assess the potential for released hazardous materials to travel off site and affect the public, staff analyzed several aspects of the proposed use of these materials at the facility. Staff recognizes that some hazardous materials must be used at power plants. Therefore, staff conducted its analysis by examining the choice and amount of chemicals to be used, the manner in which the applicant will use the chemicals, the manner by which they will be transported to the facility and transferred to facility storage tanks, and the way the applicant plans to store the materials on site.

Staff reviewed the applicant's proposed engineering and administrative controls concerning hazardous materials usage. Engineering controls are the physical or mechanical systems, such as storage tanks or automatic shut-off valves, that can prevent the spill of hazardous material from occurring, or which can either limit the spill to a small amount or confine it to a small area. Administrative controls are the rules and procedures that workers at the facility must follow that will help to prevent accidents or to keep them small if they do occur. Both engineering and administrative controls can act as methods of prevention or as methods of response and minimization. In both cases, the goal is to prevent a spill from moving off site and causing harm to the public.

Staff reviewed and evaluated the applicant's proposed use of hazardous materials as described by the applicant (HEI 2008c, Section 5.12). Staff's assessment followed the five steps listed below.

Step 1: Staff reviewed the chemicals and the amounts proposed for on-site use as listed in **Tables 5.12-1 through 5.12-4** of the AFC (HEI 2008c) and determined the need and appropriateness of their use.

Step 2: Those chemicals proposed for use in small amounts or whose physical state is such that there is virtually no chance that a spill would migrate off site and impact the public were removed from further assessment.

Step 3: Measures proposed by the applicant to prevent spills were reviewed and evaluated. These included engineering controls such as automatic shut-off valves and different-sized transfer-hose couplings and administrative controls such as worker training and safety management programs.

Step 4: Measures proposed by the applicant to respond to accidents were reviewed and evaluated. These mitigation measures also include engineering controls such as catchment basins and methods to keep vapors from spreading and administrative controls such as training emergency response crews.

Step 5: Staff analyzed the theoretical impacts on the public of a worst-case spill of hazardous materials, as reduced by the mitigation measures proposed by the applicant. When mitigation methods proposed by the applicant are sufficient, no further mitigation is recommended. If the proposed mitigation is not sufficient to reduce the potential for adverse impacts to an insignificant level, staff will propose additional prevention and response controls until the potential for causing harm to the public is reduced to an insignificant level. It is only at this point that staff can recommend that the facility be allowed to use hazardous materials.

DIRECT/INDIRECT IMPACTS AND MITIGATION

The proposed HECA project would consist of a complex industrial facility similar in scope to a small refinery. The presence of numerous chemical processes, specifically the larger gasification process and sulfur recovery process that will require large amounts of hazardous materials in closed tanks and piping at elevated temperature and pressure pose significant risks if not managed properly. Staff has not encountered such a complex power generation facility in the history of the Energy Commission.

In order to properly review the hazardous materials proposed for use at this project, as well as those that will be produced by the project, staff reviewed the entire gasification system and ancillary processes and visited a similar gasification facility, the Polk Power Station near Tampa, Florida. During that visit, staff discussed routine and accidental emissions, frequency of flares and upset conditions, fugitive emissions from piping, flanges, valves, and pumps, the Process Safety Management analysis for a potential syngas explosion, fire detection and suppression systems, waste streams, and general operating information. According to the owners of the Polk Power Station, there have been no significant accidental releases of hazardous materials or significant fires or explosions in the history of the power plant (commercial operations started in September 1986). There have been, however, frequent incidences of small syngas fires/explosions during start-ups and shut-downs. If the explosion occurs in the gasifier, the vessel contains the explosion.

Nevertheless, as a result of staff’s efforts to understand the process and the risks involved, staff determined that the number and large volumes of hazardous materials and the processes that use these hazardous materials must be assessed and managed in greater detail than usual, regardless if the quantities of materials present are below federal or state thresholds for regulation. The procedure staff used was modified to address the volumes and elevated temperature and pressures that the facility would operate under. Staff therefore reviewed the entire list of hazardous materials provide by the applicant and will require strict adherence to **HAZ-1** so that any deviation from this list is reviewed and approved in advance by the CPM.

The reasons staff made the decisions to require additional mitigation measures beyond standard administrative and engineering controls for certain hazardous materials can be found in **HAZARDOUS MATERIALS MANAGEMENT Table 2.**

HAZARDOUS MATERIALS MANAGEMENT Table 2
Additional Mitigation Needs

Material	Application	Maximum Quantity On Site	Further Review and Mitigation	Reasons for Yes/No Mitigation
Ammonium Lignosulfonate	Slurry prep bldg for maintaining % solids in slurry	63,000 gallons	No	Extremely low vapor pressure thus little risk of off-site impacts.
Aqueous Ammonia 19% Solution	Emissions control (SCR), gasifier pH control	20,000 gallons	**Yes**	High vapor pressure; high volume
Boiler Feedwater Chemicals (e.g., Carbonic Dihydrazide, Morpholine, Cyclohexamine, Sodium Sulfite)	Boiler feedwater pH/corrosion / dissolved oxygen/biocide control	< 500 gallons	No	Very small quantity and low vapor pressures; aqueous mixtures.
Chemical Reagents (acids/bases/standards)	Lab	< 5 gallons	No	Very small quantities.
Combustion Turbine Wash Chemicals (specialty detergents and surfactants)	Combustion turbine cleaning	Intermittent use/cleaning by contractor	No	Intermittent use and low toxicity of cleaners and surfactants.
Compressed Carbon Dioxide Gas	Generator purging and fire protection	50,000 standard cubic feet for purging	No	Small volume and low off-site hazard.
Compressed Gases (Ar, He, H^2)	Lab	Minimal	No	Very small volumes.
Cooling Water Chemical Additives (e.g., Magnesium Nitrate, Magnesium Chloride)	Corrosion inhibitor/biocides	< 500 gallons	No	Very small volumes; pose little risk off-site.
CTG and HRSG Cleaning	HRSG chemical cleaning	Intermittent cleaning requirement/	no	Intermittent use; standard admin and engineering controls adequate to prevent off-site

Chemicals (e.g., HCl, Citric Acid, EDTA Chelant, Sodium Nitrate)		temp storage only		impacts.
Diesel Fuel	Emergency generator/fire water pump fuel	2,000 gallons	no	Standard admin and engineering controls adequate to prevent off-site impacts.
Diethylene Glycol Monobutyl Ether (Industrial Cleaner)	Routine cleaning, degreasing, oxygen pipeline cleaning	None	no	Almost none stored on-site.
Flammable/Hazardous Gases (H_2, CO, H_2S), Syngas and Hydrogen-Rich Gas	Primary power generation fuel	In process quantities only, no storage on site	**Yes**	Highly flammable or toxic.
Hydrogen	STG & CTG generator cooling	29,000 standard cubic feet	no	Small volume.
Methanol	Gasifier startup-fuel, AGR solvent make-up	550,000 gallons	**Yes**	Toxic, flammable liquid at elevated temp and pressure.
Methyldiethanolamine (40%)	Solvent for sulfur removal	220,000 pounds	no	Low vapor pressure.
Miscellaneous Industrial Gases – Acetylene, Oxygen, Other welding Gases, Analyzer Calibration Gases	Maintenance welding/ instrumentation calibration	Minimal	no	Very small volumes and low toxicity; little risk of off-site impacts.
Molten Sulfur	By-product for sale	150,000 gallons	no	Solid and non-volatile; low toxicity.
Natural Gas	Startup/backup/ auxiliary fuel	Utility supply on demand via pipeline	**Yes**	Highly flammable
Nitrogen	Syngas fuel diluent for NOx control, inert gas	50 tons	no	Inert gas.
Oxygen (95%), Liquid	Gasification, SRU	1,200 tons	**Yes**	Highly corrosive and high risk of accelerating a fire.
Paint, Thinners, Solvents, Adhesives, etc.	Shop/warehouse	< 20 gallons	no	Very low volumes and low toxicity.
Propylene Glycol (100%)	Heat transfer fluid	< 300 gallons	no	Very low volumes and low toxicity.
Propylene Glycol (45%)	Heat transfer fluid	25,000 gallons	no	Very low vapor pressure and low toxicity of aq. Soln (aqueous solution).
Sodium Bisulfite	Raw water treatment	< 500 gallons	no	Very low volumes and low vapor pressure.
Sodium	Raw water	7,000 gallons	no	Very low vapor pressure, aq.

Hypochlorite	treatment and cooling tower biological control			soln., and low toxicity.
Sodium Hydroxide (5% - 50%)	Plant wastewater ZLD, sour water treatment, gasification, caustic scrubber	60,000 gallons	no	Very low vapor pressure and aq. soln.
Sodium Phosphate	Raw water treatment, gasification, plant wastewater ZLD	1,500 gallons	no	Very low vapor pressure, aq. soln.
Sulfuric Acid	Plant wastewater ZLD	2,000 gallons	no	Very low vapor pressure.
Sulfuric Acid	Cooling water, BFW pH control	12,000 gallons	no	Very low vapor pressure.
Water Treatment Chemicals	Raw water, demineralized water, and cooling water treatment	< 500 gallons	no	Very low vapor pressure, aq. soln., and small volumes.

Source: HEI 2008c,Tables 5.12-3 & 5.12-4

Small Quantity/Low Risk Hazardous Materials

Hazardous chemicals such as hydrogen, sulfuric acid, molten sulfur, mineral and lubricating oils, cleaning detergents, welding gasses, and other various chemicals would be used and/or temporarily stored at the HECA site. (See **Hazardous Materials Appendix B** for a list of all chemicals proposed for use and storage at HECA). In conducting the analysis, staff determined in Steps 1 and 2 that these materials, although present at the proposed facility, pose a minimal potential for off-site impacts since they will be stored either in small quantities, used in an enclosed system, have low mobility/volatility, or have low levels of toxicity. These hazardous materials are eliminated from further consideration. [note: A large amount of carbon dioxide will be transported via pipeline to the Elk Hills Oil Field and federal regulations (49 CFR 195) required the applicant to prepare a risk analysis for the pipeline. The risk analysis determined that the risk of pipeline failure was less than significant.]

After removing from consideration those chemicals that pose no risk of off-site impact in Steps 1 and 2, staff continued with Steps 3, 4, and 5 to review the remaining large quantity hazardous materials:

1. natural gas
2. syngas
3. methanol
4. liquid oxygen
5. aqueous ammonia.

The project will be limited to using, storing, and transporting only those hazardous materials listed in Appendix B of this document as per staff's proposed condition **HAZ-1**.

Large Quantity Hazardous Materials

Natural Gas

Natural gas poses a fire and/or possible explosion risk because of its flammability. Natural gas is composed mostly of methane, but also contains ethane, propane, nitrogen, butane, isobutene, and isopentane. It is colorless, odorless, and tasteless and is lighter than air. Natural gas can cause asphyxiation when methane is 90% in concentration. Methane is flammable when mixed in air at concentrations of 5 to 14%, which is also the detonation range. Natural gas, therefore, poses a risk of fire and/or possible explosion if a release occurs under certain specific conditions. However, it should be noted that, due to its tendency to disperse rapidly (Lees 1998), natural gas is less likely to cause explosions than many other fuel gases such as propane or liquefied petroleum gas, but can explode under certain conditions (as demonstrated by the July 2004 natural gas detonation in Belgium).

While natural gas would be used in significant quantities, it would not be stored on site. It would be delivered via a new pipeline that will connect to one of two natural gas pipelines provided by either Sothern California Gas Company or Pacific Gas and Electric (PG&E). Both pipelines are located approximately 8 miles from the project site (HEI 2008c, Section 5.12.2.2). The risk of a fire and/or explosion on site can be reduced to insignificant levels through adherence to applicable codes and the development and implementation of effective safety management practices. The National Fire Protection Association (NFPA) code 85A requires both the use of double-block and bleed valves for gas shut off and automated combustion controls. These measures will significantly reduce the likelihood of an explosion in gas-fired equipment. Additionally, start-up procedures would require air purging of the gas turbines prior to start up, thereby precluding the presence of an explosive mixture. The safety management plan proposed by the applicant would address the handling and use of natural gas and would significantly reduce the potential for equipment failure because of either improper maintenance or human error.

Since the proposed facility will require the installation of a new gas pipeline off-site, impacts from this pipeline need to be evaluated. The new gas pipeline proposed for this project would be constructed, owned and operated by Southern California Gas Company or PG&E (HEI 2008c, Section 2.1.8.3). The design of the natural gas pipeline is governed by laws and regulations discussed here. These LORS require use of high quality arc welding techniques by certified welders and inspection of welds. Many failures of older natural gas lines have been associated with poor quality welds, or corrosion. Current codes address corrosion failures by requiring use of corrosion resistant coatings and cathodic corrosion protection. Another major cause of pipeline failure is damage resulting from excavation activities near pipelines. Current codes address this mode of failure by requiring clear marking of the pipeline route. An additional mode of failure is damage caused by earthquake. Existing codes also address seismic hazard in design criteria (see discussion below). Evaluation of pipeline performance in recent earthquakes indicates that pipelines designed to modern codes perform well in seismic events while older lines frequently fail. Staff believes that existing regulatory requirements are sufficient to reduce the risk of accidental release from the pipeline to insignificant levels.

Failures of gas pipelines, according to data from the U.S. Department of Transportation (the National Transportation Safety Board) from the period 1984 – 1991 and data from the National Response Center for the period 1990 - 2004 , occur as a result of pipeline corrosion, pipeline construction or materials defects, rupture by heavy equipment excavating in the area such as bulldozers and backhoes, weather effects, and earthquakes. Given the gas line failures which occurred in the Marina District of San Francisco during the 1989 Loma Prieta earthquake, the January 1994 Northridge earthquake in Southern California, the January 1995 gas pipeline failures in Kobe, Japan, the January 19, 1995 gas explosion in San Francisco, the pipeline explosion in Belgium in July 2004, and the natural gas storage fire in Texas in August 2004, the safety of the gas pipeline is of paramount importance. However, it must be noted that those pipelines which failed in 1989 to 1995 were older and not manufactured nor installed to modern code requirements. The February 2001 Nisqually Earthquake near Olympia Washington caused no damage to natural gas mains and there was only one reported gas line leak due to a separation of a service line going into a mobile home park. The Belgium gas pipeline explosion was due to construction equipment rupturing the line, not due to earthquake or structural failure.

If loss of containment occurs as a result of pipe, valve, or other mechanical failure or external forces, significant quantities of compressed natural gas could be released rapidly. Such a release can result in a significant fire and/or explosion hazard, which could cause loss of life and/or significant property damage in the vicinity of the pipeline route. However, the probability of such an event is extremely low if the pipeline is constructed according to present standards. According to DOT statistics, the frequency of reportable incidents is about 0.25 for all pipeline incidents per 1,000 miles per year or 2.5×10^{-4} incidents per mile per year. DOT has also evaluated and categorized the major causes of pipeline failure. To summarize, the four major causes of accidental releases from natural gas pipelines are: Outside Forces - 43%, Corrosion -18%, Construction/Material Defects -13%, and Other - 26%. Outside forces are the primary causes of incidents. Damage from outside forces includes damage caused by use of heavy mechanical equipment near pipelines (e.g., bulldozers and backhoes used in excavation activities), weather effects, vandalism, and earthquake-caused rupture as seen in the Marina District of San Francisco during the 1989 Loma Prieta Quake and in Kobe, Japan in January 1995. The fourth category, “Other” includes equipment component failure, compressor station failures, operator errors and sabotage. The average annual service incident frequency for natural gas transmission systems varies with age, the diameter of the pipeline, and the amount of corrosion. Older pipelines have a significantly higher frequency of incidents. These result from the lack of corrosion protection and use of less corrosion resistant materials compared to modern pipelines, limited use of modern inspection techniques, and higher frequency of incidents involving outside forces. The increased incident rate due to outside forces is the result of the use of a larger number of smaller diameter pipelines in older systems, which are generally more easily damaged and the uncertainty regarding the locations of older pipelines.

The safety requirements for pipeline construction vary according to the population density and land use, which characterize the surrounding land. The pipeline classes are defined as follows (Title 49, Code of Federal Regulations, Part 192):

Class 1: Pipelines in locations within 220 yards of ten or fewer buildings intended for human occupancy in any 1-mile segment.

Class 2: Pipelines in locations within 220 yards of more than ten but fewer than 46 buildings intended for human occupancy in any 1-mile segment. This class also includes drainage ditches of public roads and railroad crossings.

Class 3: Pipelines in locations within 220 yards of more than 46 buildings intended for human occupancy in any 1-mile segment, or where the pipeline is within 100 yards of any building or small well-defined outside area occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12 month period (the days and weeks need not be consecutive). (The proposed project gas pipeline would fall into this class.)

Class 4: Pipelines in locations within 220 yards of buildings with 4 or more stories above ground in any 1-mile segment.

In the United States, extensive federal and state pipeline codes and safety enforcement minimize the risk of severe accidents related to natural gas pipelines. In November 2000, the DOT Office of Pipeline Safety proposed a program requiring the preparation of risk management plans for gas pipelines throughout the United States. These risk management plans will include the use of diagnostic techniques to detect internal and external corrosion or cracks in pipelines and to perform preventive maintenance. The pipeline owner will be required to develop and implement these plans as per the regulation adopted May 2004 (49 CFR Part 192). The regulations prescribe minimum requirements for a pipeline Integrity Management Program to be prepared and followed by every operator of a pipeline segment located in a high consequence area. A high consequence area is defined as any location where the pipeline traverses a Class 3 or 4 area (see above) or other areas under specified circumstances. The integrity management program must contain the required elements as described in section 192.911 including an identification of all high consequence areas, a baseline assessment plan including methods of assessing pipeline integrity and a schedule for completing the assessment, an identification of threats to each pipeline segment including a risk assessment, an evaluation of mitigation measures, implementation procedures, and monitoring procedures. The regulations also include requirements for reassessment intervals, which range from 7 to 20 years depending on the type of reassessment and the operating percentage of the pipeline.

The following safety features will be incorporated into the design and operation of the natural gas pipeline (as required by current federal and state codes): (1) while the pipeline will be designed, constructed, and tested to carry natural gas at a certain pressure, the working pressure will be less than the design pressure; (2) butt welds will be X-rayed and the pipeline will be tested with water prior to the introduction of natural gas into the line; (3) the pipeline will be surveyed for leakage annually (4) the pipeline will be marked to prevent rupture by heavy equipment excavating in the area; and (5) valves at the meter will be installed to isolate the line if a leak occurs. These requirements will be administered by the federal government and the CPUC. The natural gas pipeline must be designed to meet all standards of the California Public Utilities Commission General Order 112 and 49 CFR Parts 190 through192. CPUC General Order 112-E, Section 125.1 requires that at least 30 days prior to the construction of a new pipeline, the owner must file a report with the commission that will include a route map for the pipeline. The natural gas pipeline must also be constructed and operated in accordance with the Federal Department of Transportation (DOT) regulations, Title 49, Code of Federal Regulations (CFR), Parts 190, 191, and 192 (see Table 1 LORS). Staff concludes that compliance with existing LORS would be sufficient to ensure minimal risks of pipeline failure.

The syngas would be used as a fuel and produced on-demand such that there will be minimal storage on site in the gasifier and other piping. However, syngas contains a very high concentration of carbon monoxide (CO), an extremely toxic chemical. The applicant modeled a worst-case release of CO from the gasifier and determined that ground level airborne concentrations would not exceed the Immediate Dangerous to Life and Health (IDLH) level of 1200 ppm or the OSHA Short-term Exposure Level (STEL). However, the applicant misspoke as there is no CalOSHA or U.S. OSHA STEL for carbon monoxide; only a Permissible Exposure Level (PEL) and Ceiling Level (25 ppm and 200 ppm, respectively for CalOSHA and a U.S. OSHA PEL of 50 ppm). Also, this modeling did not address the recent Cal EPA Acute Reference Exposure Level (REL) of 20 ppm and therefore staff considers this modeling inadequate to address risks to the on-site workers or the off-site public.

Syngas

Syngas poses a fire and/or possible explosion risk because of its flammability. Syngas contains hydrogen (H_2), carbon monoxide (CO), sulfur dioxide (SO_2), and hydrogen sulfide (H_2S). Syngas has a broader flammable and detonation range than natural gas because it is a mixture of chemicals with more diverse properties. Syngas also contains an extremely hazardous material, H_2S, which is scrubbed from the syngas and subsequently removed from the enclosed process system and mostly converted to elemental sulfur, a solid powder with low potential for migration or adverse impacts on the off-site public. It is then transferred for sale off-site. Up to 150,000 gallons of degassed molten sulfur will be stored on site in two sulfur storage pits. The storage pits will also be equipped with pressure-monitoring equipment and ventilation lines while the sulfur-loading equipment will have a vapor recovery system to control fugitive emissions of hydrogen sulfide by returning vapors to the SRU.

A catastrophic loss of the syngas would result in the release of significant amounts of H_2S and thus the applicant modeled a worst-case accidental release. Staff addresses the emissions of H_2S into the atmosphere as an accidental release in this section and as fugitive emissions from the process system in the **Public Health** section of this PSA.

The applicant's modeling of an accidental release of hydrogen sulfide shows that the acute Reference Exposure Level (REL) would not be exceeded at off-site locations where the public drives and lives. Staff has also found that the modeling of fugitive emissions of H_2S emitted from the CO_2 vent shows that the acute REL would also not be exceeded, thus indicating no potential for adverse impacts to the public. (See the **Public Health** section for a thorough analysis of this issue.)

Hydrogen sulfide can be released from a failure of the sulfur recovery unit (SRU).

Staff reviewed the past accident history of SRUs in California over the past 20 years and found that although there have been numerous releases of sulfurous chemicals at refineries in California (over 1,600 in the past 20 years), only about 80 of the reports specify the sulfur recovery unit as the source of the release. Thus, many of the incidents could involve components of a sulfur recovery system since it is a common system in refineries.

The vast majority of the reports of accidental releases at SRUs in California found in the National Response Center (NRC) database show that most releases consist of sulfur dioxide (SO_2) and not H_2S. However, SO_2 will be produced in great quantities during the gasification process at the proposed HECA project and then will be combined with H_2S to produce elemental sulfur. (Sulfur dioxide will also be released from several sources into the atmosphere including the main stack, the SRU, and the Tail Gas Thermal Oxidizer). Therefore, because SO_2 will be produced by the HECA process, staff finds the reports of releases from refinery SRUs to be germane to the safety of the proposed process.

Examples of SRU upsets include:

- September 2008 at Big West of Ca, Bakersfield: A release of sulfur dioxide above the reportable quantity occurred due to failure in the sulfur recovery system. Amount released unknown, no fires, injuries or evacuation reported.
- December 2004 at Exxon Mobil Refinery, Torrance: Sulfur dioxide was released from the sulfur recovery unit when the analyzer maxed out because the facility was in the middle of switching the sour water strippers. No fires, injuries or evacuation reported.
- June 2003 at Valero Refining Co, Benicia: A flaring incident of sulfur dioxide occurred; the release was caused by an upset in the sulfur recovery unit. Amount released: 630 pounds. No fires, injuries, or evacuation reported.
- Shell Martinez Refinery (March 2006) reported via the Community Warning System a release of sulfur dioxide gas from the stack of Sulfur Recovery Plant #3 (SRU#3). Visible pluming stopped within 15 minutes. Shell Avenue was closed for 25 minutes. Refinery officials did not report any visible external damage to equipment. There may have been elevated temperatures in one of the catalyst beds that resulted in producing sulfur dioxide gas.
- Shell, Martinez, CA (April 2002) Sulfur Recovery Unit #3 was being shut down on the morning of 4/23/02 to address concerns about SO_2 stack emissions, which were approaching the BAAQMD limit of 250 ppm/hr. SRU#3 converts acid gas consisting of SO_2 and H_2S to elemental sulfur in a catalytic reactor utilizing the "Claus" process, the same process proposed for the HECA project. The SRU#3 vent gas is routed through a Shell Claus Offgas Treatment (SCOT) plant for additional treatment. The SCOT-3 vent gas is routed through a catalytic oxidizer to convert remaining H_2S to SO_2. By 11:00 am all acid gas feed had been removed from SRU#3. Approximately an hour later, the catalytic oxidizer experienced a temperature excursion (most likely resulting from burning sulfur), which led to a plume from the SCOT-3 stack by 12:30 p.m. At 12:30 p.m., Shell called the incident a Level 1 alert. At 12:35 am, Shell upgraded the incident to a Community Warning System Level 3 alert and sounded

sirens. Steam and nitrogen were used to cool the catalytic oxidizer. Contra Costa County Health Services field observations identified a black plume, which dissipated very quickly and no plume was visible after about 10 or 15 minutes. Shell secured the unit at 12:57 pm.

- Chevron, Richmond, CA (January 2002) Release of sulfur dioxide from the #3 SRU plant. A high vapor/liquid flow condition was created by the Isomax #4 H2S plant when a normal heat exchanger backwash was being performed, which caused an interlock plant shutdown at #3 SRU. The momentary release occurred while restarting the plant.(Level 3 initiated by CCHS.) A few calls were reported to the facility expressing concern or inquiring as to the activity taking place. People in Richmond were asked to shelter-in-place.
- Tosco (now Conoco Phillips) CA (April 1997) An upset in the distillation unit sent hydrocarbons to the sulfur recovery units. Parts of the refinery were shut down until the problem was found. People were asked to shelter-in-place at Tormey and Crockett.

Although minor sulfur dioxide releases and other small incidents are common at sulfur recovery units, such incidents rarely produce fires, injuries, significant damage, or a need for evacuation. Sulfur recovery units at California facilities recorded roughly 100 incidents over the past 20 years, most of them without significant consequences. Therefore, staff proposes to address the risk management of this hazardous material by requiring a Process Safety Management Plan (PSM Plan, which includes a Hazard and Operability analysis) and a Risk Management Plan (RMP, which would include a new Offsite Consequence Analysis).

Methanol

Methanol (methyl alcohol) will be used as a gasifier start-up fuel and in the acid gas remover (AGR) and sulfur recovery unit. This use will be at elevated temperature and pressure thus increasing the potential for an accidental release, explosion, or fire. The applicant addressed the risk and impacts of a vapor cloud explosion and fire of the above-ground storage tank holding 300,000 gallons of methanol. Worst-case modeling indicated that a pressure wave of 1 psi would impact up to 4224 feet distant from the tank location. This impact would be beyond the Controlled Area and may impact the nearest residence (1400 feet from the control area fence line) but would not cause an impact at the school located 1.3 miles (6864 feet) away.

Staff proposes to address the risk management of this hazardous material by requiring a Process Safety Management Plan (PSM Plan, which includes a Hazard and Operability analysis) and a Risk Management Plan (RMP, which would require a new Offsite Consequence Analysis addressing explosion and fire). Staff believes that these plans will identify potential system failures and mitigation and thus reduce the risk of off-site consequences to the public to less than significant. The applicant also will reduce the risk of fire or explosion at the methanol tank by utilizing an aqueous film forming foam as the fire suppression system.

Liquid Oxygen

Liquid oxygen is a compressed gas stored as a cryogenic liquid. As such, it is extremely corrosive and a potent oxidizer. Should a fire occur near the tank and the tank or fittings rupture, a conflagration could ensue. Staff researched the incident rates of accidents and releases involving liquid oxygen tanks in the past 20 year and found that although the rate was low, they do occur. A review of the 15 incidents of liquefied oxygen releases in the United States alone found that worker deaths and injuries are not common and thus liquid oxygen storage does not pose a significant risk. Of these 15 incidents, 13 releases were due to the failures of valves, fittings, pipe leaks, gauges, and delivery vehicle hose couplings, or involved a small (20 cu ft) tank rupture due to a fall. In most cases, only a few hundred pounds of liquid oxygen was released, however, in one case, >20,000 pounds escaped. In 1999, in Bristol, MA, an oxygen bulk tank exploded and released 200 gallons. No injuries or evacuation reported and the cause of the failure was not determined. In February 1978, three persons were killed in New Martinsville, WV when liquid oxygen escaping from a pipe at a chemical plant set off a very large explosion and fire. All land, air and river traffic was halted for about seven hours while officials waited for the 900-ton liquid oxygen tank to exhaust its supply. The cause was determined to be a pipe rupture at an air separation facility when a liquid nitrogen vessel broke and a portion fell on the liquid oxygen pipe.

Staff proposes to address the risk management of this hazardous material by requiring a Process Safety Management Plan (PSM Plan, which includes a Hazard and Operability analysis) and a Risk Management Plan (RMP, which includes an Offsite Consequence Analysis). The applicant will also install pressure relief valves and automatic shutdown equipment for the tank and oxygen delivery system that will reduce the likelihood of an accidental release. Staff believes that these plans will identify potential system failures and additional mitigation and thus, when combined with the applicant's proposed controls, will reduce the risk of off-site consequences to the public to less than significant.

Aqueous Ammonia

Aqueous ammonia would be used to control the emission of oxides of nitrogen (NO_X) from the combustion of natural gas at the HECA project. The accidental release of aqueous ammonia without proper mitigation can result in significant down-wind concentrations of ammonia gas. HECA would store 19% aqueous ammonia solution in an above-ground ammonia tank with a maximum capacity of 20,000 gallons (HEI 2008c, Sections 5.12.5.3). The tank would be surrounded by a secondary containment basin capable of holding the full contents of the tank plus the rainfall associated with a 24-hour 25-year storm. The secondary containment would be covered with high-density polyethylene floating balls which reduce the surface area of evaporating liquid by approximately 90%, thereby minimizing the impacts of an accidental spill. The truck unloading area would be constructed with an underground containment vault designed to minimize ammonia evaporation in case of a spill (HEI 2008c, Sections 5.12.5.3).

Based on staff's analysis described above, aqueous ammonia is the only hazardous material that may pose a significant risk of off-site impact. The use of aqueous ammonia can result in the release of ammonia vapor in the event of a spill. This is a result of its moderate vapor pressure and the large amounts of aqueous ammonia that will be used and stored on site. However, the use of aqueous ammonia poses far less risk than the use of the far more hazardous anhydrous ammonia (ammonia that is not diluted with water).

To assess the potential impacts associated with an accidental release of aqueous ammonia, staff uses four benchmark exposure levels of ammonia gas occurring off site. These include:

1. the lowest concentration posing a risk of lethality, 2,000 parts per million (ppm);
2. the concentration immediately dangerous to life and health level of 300 ppm;
3. the emergency response planning guideline level 2 of 150 ppm, which is also the RMP level 1 criterion used by U.S. Environmental Protection Agency (EPA) and California; and
4. the level considered by the Energy Commission staff to be without serious adverse effects on the public for a one-time exposure of 75 ppm.

If the potential exposure associated with a potential release exceeds 75 ppm at any public receptor, staff will also assess the probability of occurrence of the release, the severity of the consequences, and the nature of the potentially exposed population in determining whether the likelihood and extent of potential exposure are sufficient to support a finding of potentially significant impact. A detailed discussion of the exposure criteria considered by staff, as well as their applicability to different populations and exposure-specific conditions, is provided in **HAZARDOUS MATERIALS Appendix A**.

Section 5.12.2.3 and **Appendix L** of the AFC (HEI 2008c) describe the modeling parameters used for the worst-case and the alternative accidental releases of aqueous ammonia in the applicant's off-site consequence analysis (OCA). Pursuant to the California Accidental Release Program (CalARP) regulations (federal risk management plan regulations do not apply to sources that store or use aqueous ammonia solutions below 20%), the OCA was performed for the worst-case release scenario, which involved the failure and complete discharge of the storage tank. The highest average recorded temperature (115°F), a wind speed of 1.5 meters per second, and atmospheric stability class F were used for emission and dispersion calculations to present worst-case conditions. Potential off-site ammonia concentrations were estimated using the ALOHA Gaussian plum model (HEI 2008c, **Appendix L** Section 3.1.1).

HAZARDOUS MATERIALS MANAGEMENT Table 2 shows the applicant's modeled distance to four benchmark criteria concentrations.

HAZARDOUS MATERIALS MANAGEMENT Table 2
Distance to Selected Toxic Endpoints

Scenario	Distance in Feet to Lethal Concentration (2,000 ppm)	Distance in Feet to IDLH (300 ppm)	Distance in Feet to CalARP's (200 ppm)	Distance in Feet to CEC's threshold (75 ppm)
Worst Case	60	162	189	318

Source: Table Appendix L Section 3.2.1 (HEI 2008c) and Data Response #84 (URS 2009j)

Figure L-1 of Appendix L (HEI 2008c) and Figure 84-1 of Data Response #84 show how far the predicted ammonia concentrations would extend from the ammonia tank. The applicant's modeling results show that ammonia concentrations exceeding 75 ppm would not reach the facility fence line and therefore no off-site impacts are expected.

Since the applicant's modeling is very conservative and most likely overestimates the airborne concentration of ammonia should an accidental release occur from the storage tank or during transfer operations, staff concludes that the applicant's modeling demonstrates no off-site impact. Staff therefore believes that the applicant's proposed engineering controls will ensure protection of public health.

Mitigation

The potential for accidents resulting in the release of hazardous materials is greatly reduced through implementation of a safety management program that would include the use of both engineering and administrative controls. Elements of both facility controls and the safety management plan are summarized below.

Engineering Controls

Engineering controls help to prevent accidents and releases (spills) from moving off site and affecting communities by incorporating engineering safety design criteria in the design of the project. The engineered safety features proposed by the applicant for use at the HECA project include:

- storage of containerized hazardous materials in their original containers which are designed to prevent releases and are appropriately labeled;
- construction of secondary containment areas surrounding each of the hazardous materials storage areas designed to contain accidental releases that might happen during storage or delivery;
- physical separation of stored chemicals in isolated containment areas in order to prevent accidental mixing of incompatible materials, which could result in the evolution and release of toxic gases or fumes;
- installation of local level gauges and alarms to prevent overfilling of bulk chemical storage tanks;
- construction of a containment area surrounding the aqueous ammonia storage tank, sodium hydroxide tanks, sulfuric acid tank, sodium hypochlorite tank, diesel fuel tank, and lubricating oil tank capable of holding the entire contents of each tank plus the volume of rainfall associated with a 24-hour 25-year storm;

- use of floating plastic balls in the aqueous ammonia containment area that would reduce the surface area of evaporating liquid by 90% and the placement of a subsurface vault;
- construction of a paved concrete pad surrounding the aqueous ammonia truck unloading area that drains into an underground containment structure; and
- process protective systems including continuous tank level monitors, automated leak detectors, ammonia and hydrogen sulfide detectors, temperature and pressure monitors, alarms, and isolation valves.

Administrative Controls

Administrative controls also help prevent accidents and releases (spills) from moving off site and affecting neighboring communities by establishing worker training programs, process safety management programs, and complying with all applicable health and safety laws, ordinances, and standards.

A worker health and safety program will be prepared by the applicant and include (but not be limited to) the following elements (see the **Worker Safety and Fire Protection** section for specific regulatory requirements):

- worker training regarding chemical hazards, health and safety issues, and hazard communication;
- procedures to ensure the proper use of personal protective equipment;
- safety operating procedures for the operation and maintenance of systems utilizing hazardous materials;
- fire safety and prevention; and
- emergency response actions including facility evacuation, hazardous material spill clean-up, and fire prevention.

At the facility, the project owner will be required to designate an individual with the responsibility and authority to ensure a safe and healthful work place. The project health and safety official will oversee the health and safety program and have the authority to halt any action or modify any work practice to protect the workers, facility, and the surrounding community in the event of a violation of the health and safety program.

The applicant will also prepare a risk management plan for aqueous ammonia, as required by both CalARP regulations and Condition of Certification **HAZ-2**. This condition also includes the requirement for a program for the prevention of accidental releases and responses to an accidental release of aqueous ammonia. A hazardous materials business plan will also be prepared by the applicant that would incorporate state requirements for the handling of hazardous materials (HEI 2008c, Section 5.12.2.2). Additional administrative controls are required by **HAZ-2** include preparation of a Hazardous Materials Business Plan, a Process Safety Management Plan for several processes, and a Spill Prevention, Control, and Countermeasure Plan). Other administrative controls would be required in proposed Conditions of Certification **HAZ-1** (limitations on the use and storage of hazardous materials and their strength and volume) and **HAZ-3** (development of a safety management plan). Proposed Condition

HAZ-4 would require that the aqueous ammonia storage tank be designed to certain specifications.

The applicant has also proposed several Conditions of Certification. Those that are accepted by staff can be found in proposed Condition of Certification **HAZ-10**.

On-Site Spill Response

In order to address the issue of spill response, the facility will prepare and implement an emergency response plan that includes information on hazardous materials contingency and emergency response procedures, spill containment and prevention systems, personnel training, spill notification, on-site spill containment, and prevention equipment and capabilities, as well as other elements. Emergency procedures will be established which include evacuation, spill cleanup, hazard prevention, and emergency response.

The presence of oil in a quantity greater than 1,320 gallons might invoke a requirement to prepare a Spill Prevention Control and Countermeasures (SPCC) Plan. The applicant has indicated that 2000 gallons of diesel fuel will be stored on site. However, there are no known waters of the United States immediate adjacent to this site but there are Waters of the State and thus staff's position is that a SPCC Plan is required by 40 CFR 112. State law also applies in that pursuant to California HSC Sections 25270 through 25270.13, the project will store 10,000 gallons or more of petroleum on-site (when the lube oil and the transformers oil are included). The above regulations would also require the immediate reporting of a spill or release of 42 gallons or more to the California Office of Emergency Services and the Certified Unified Program Authority (CUPA).

Designated plant personnel would be trained as first responders for hazardous materials incidents. In the event of a large spill, the Kern County Fire Department Hazmat Response Unit located in Bakersfield would respond to the project site, and contracted hazardous materials clean-up teams would also be available (HEI 2008c, Section 5.12.5.3 and 5.8.1.3). Staff finds that the available local hazmat teams and clean-up companies are capable of responding to a hazardous materials emergency call from HECA with an adequate response time.

Transportation of Hazardous Materials

Hazardous materials including aqueous ammonia will be transported to the facility by tanker truck. While many types of hazardous materials will be transported to the site, staff believes that transport of aqueous ammonia poses the predominant risk associated with hazardous materials transport.

Staff reviewed the applicant's proposed transportation routes for hazardous materials delivery. Trucks would travel from Bakersfield using Stockdale Highway to Dairy Road to Adohr Road to the project's gate (HEI 2008c, Section 5.12.3 and Figure 5.12-2). Alternative routes will only be used if hazardous materials are transported from non-major suppliers.

Ammonia can be released during a transportation accident and the extent of impact in the event of such a release would depend upon the location of the accident and the rate of dispersion of ammonia vapor from the surface of the aqueous ammonia pool. The likelihood of an accidental release during transport is dependent upon three factors:

1. the skill of the tanker truck driver;
2. the type of vehicle used for transport; and
3. accident rates.

To address this concern, staff evaluated the risk of an accidental transportation release in the project area. Staff's analysis focused on the project area after the delivery vehicle leaves the main highway (Stockdale). Staff believes it is appropriate to rely upon the extensive regulatory program that applies to the shipment of hazardous materials on California highways to ensure safe handling in general transportation (see Federal Hazardous Materials Transportation Law 49 USC §5101 et seq, DOT regulations 49 CFR subpart H, §172–700, and California Department of Motor Vehicles (DMV) regulations on hazardous cargo). These regulations also address the issue of driver competence. See AFC section 5.10 for additional information on regulations governing the transport of hazardous materials.

To address the issue of tanker truck safety, aqueous ammonia will be delivered to the proposed facility in DOT-certified vehicles with design capacities of 6,700 gallons (URS 2009j, Data Response #83). These vehicles will be designed to DOT Code MC-307. These are high-integrity vehicles designed to haul caustic materials such as ammonia. Staff has, therefore, proposed Condition of Certification **HAZ-5** to ensure that, regardless of which vendor supplies the aqueous ammonia, delivery will be made in a tanker that meets or exceeds the specifications described by these regulations.

To address the issue of accident rates, staff reviewed the technical and scientific literature on hazardous materials transportation (including tanker trucks) accident rates in the United States and California. Staff relied on six references and three federal government databases to assess the risk of a hazardous materials transportation accident.

Staff used the data from the Davies and Lees (1992) article, which references both the 1990 Harwood et al. and 1993 Harwood studies, to determine that the frequency of release for the transportation of hazardous materials in the U.S. is between 0.06 and 0.19 releases per 1,000,000 miles traveled on well-designed roads and highways. The maximum use of aqueous ammonia each year of the operation of the proposed HECA project will require a maximum of 165 tanker truck deliveries of aqueous ammonia per year, each delivering about 6,700 gallons (HEI 2008c, Table 5.12-5 and URS 2009j, Data Response # 83). Each delivery will travel approximately 24 miles from Bakersfield to the project site.

This would result in an estimated maximum of 4,000 miles of delivery tanker truck travel in the project area per year (with a full load). Staff believes that the risk over this distance is insignificant. Data from the U.S. DOT show that the actual risk of a fatality over the past five years from all modes of hazardous material transportation (rail, air, boat, and truck) is approximately 0.1 in 1,000,000.

Staff therefore believes that the risk of exposure to significant concentrations of aqueous ammonia during transportation to the facility is insignificant because of the remote possibility that an accidental release of a sufficient quantity could be dangerous to the public. The transportation of similar volumes of hazardous materials on the nation's highways is neither unique nor infrequent. Staff's analysis of the transportation of aqueous ammonia to the proposed facility (along with data from the U.S. DOT) demonstrates that the risk of accident and exposure is less than significant.

In order to further ensure that the risk of an accident involving the transport of aqueous ammonia to the power plant is insignificant, staff proposes an additional administrative control in proposed Condition of Certification **HAZ-6** that would require the use of only one specific route to the site, that being the shortest route from Bakersfield using Stockdale Highway to Dairy Road to the facility.

Based on the environmental mobility, toxicity, the quantities at the site, and frequency of delivery, it is staff's opinion that aqueous ammonia poses the predominate risk associated with both use and hazardous materials transportation. Staff concludes that the risk associated with the transportation of other hazardous materials to the proposed project does not significantly increase the risk of ammonia transportation.

Seismic Issues

It is possible that an earthquake could cause the failure of a hazardous materials storage tank. An earthquake could also cause failure of the secondary containment system (berms and dikes), as well as the failure of electrically controlled valves and pumps. The failure of all of these preventive control measures might then result in a vapor cloud of hazardous materials that could move off site and affect residents and workers in the surrounding community. The effects of the Loma Prieta earthquake of 1989, the Northridge earthquake of 1994, and the earthquake in Kobe, Japan, in January 1995, have all heightened concerns about earthquake safety.

Information obtained after the January 1994 Northridge earthquake showed that some damage was caused both to several large storage tanks and to smaller tanks associated with the water treatment system of a cogeneration facility. The tanks with the greatest damage, including seam leakage, were older tanks, while the newer tanks sustained displacements and failures of attached lines. Therefore, staff conducted an analysis of the codes and standards which should be followed when designing and building storage tanks and containment areas to withstand a large earthquake. Staff also reviewed the impacts of the February 2001 Nisqually earthquake near Olympia, Washington, a state with similar seismic design codes as California. No hazardous materials storage tanks failed as a result of that earthquake. Referring to the sections on **Geologic Hazards and Resources** and **Facility Safety Design** in the AFC, staff notes that the proposed facility will be designed and constructed to the standards of the 2007 California Building Code and the American Society of Civil Engineers standards (ASCE 7-05) for Seismic Zone 4 (HEI 2008c, Section 2.7.1).

Staff has also begun a review of the impacts of the recent earthquakes in Haiti (January 12, 2010; magnitude 7.0) and Chili (February 27, 2010; magnitude 8.8). The building standards in Haiti are extremely lax while those in Chile are as stringent and modern as California seismic building codes. Yet, the preliminary reports show a lack of impact on hazardous materials storage and pipelines infrastructure in both countries. For Haiti, this most likely reflects a lack of industrial storage tanks and gas pipelines; for Chili, this most likely reflects the use of strong safety codes.

Therefore, on the basis of what occurred in Northridge with older tanks and the lack of failures during the Nisqually earthquake (with newer tanks) and in the 2010 Chilean earthquake, staff determined that tank failures during seismic events are not probable and do not represent a significant risk to the public.

Site Security

The applicant proposes to use hazardous materials identified by the U.S. EPA as requiring the development and implementation of special site security measures to prevent unauthorized access. The U.S. EPA published a Chemical Accident Prevention Alert regarding site security (EPA 2000a), the U.S. Department of Justice published a special report entitled *Chemical Facility Vulnerability Assessment Methodology* (US DOJ 2002), the North American Electric Reliability Council published *Security Guidelines for the Electricity Sector* in 2002 (NERC 2002) as well as issued a Critical Infrastructure Protection standard for cyber security (NERC 2009), and the U.S. Department of Energy (DOE) published the draft *Vulnerability Assessment Methodology for Electric Power Infrastructure* in 2002 (DOE 2002). The energy generation sector is one of 14 areas of critical infrastructure listed by the U.S. Department of Homeland Security. On April 9, 2007, the U.S Department of Homeland Security published in the Federal Register (6 CFR Part 27) an interim final rule requiring that facilities that use or store certain hazardous materials conduct vulnerability assessments and implement certain specified security measures. This rule was implemented with the publication of Appendix A, the list of chemicals, on November 2, 2007. While the rule applies to aqueous ammonia solutions of 20% or greater and this proposed facility plans to utilize a 19% aqueous ammonia solution, staff still believes that all power plants under the jurisdiction of the Energy Commission should implement a minimum level of security consistent with the guidelines listed here.

The application for certification (AFC) indicates that security measures utilized for this facility would include a motorized security gate at the plant's main entrance equipped with a video surveillance system that would enable operators to monitor access to the site from the control room, and additional video cameras throughout the plant to monitor critical plant structures (HEI 2008c, Section 2.4.18.1).

In order to ensure that neither this project nor a shipment of hazardous material is the target of unauthorized access, staff's proposed Conditions of Certification **HAZ-7** and **HAZ-8** address both construction security and operation security plans. These plans would require implementation of site security measures consistent with the above-referenced documents.

The goal of these conditions of certification is to provide for the minimum level of security for power plants necessary for the protection of California's electrical infrastructure from malicious mischief, vandalism, or domestic/foreign terrorist attacks. The level of security needed for the HECA project is dependent upon the threat imposed, the likelihood of an adversarial attack, the likelihood of success in causing a catastrophic event, and the severity of the consequences of that event. The results of the off-site consequence analysis prepared as part of the RMP will be used, in part, to determine the severity of consequences of a catastrophic event.

In order to determine the level of security, the Energy Commission staff used an internal vulnerability assessment decision matrix modeled after the U.S. Department of Justice Chemical Vulnerability Assessment Methodology (July 2002), the North American Electric Reliability Council's (NERC) 2002 guidelines, the U.S. DOE VAM-CF model, and the U.S. Department of Homeland Security regulations published November 2007 in the Federal Register (Interim Final Rule 6 CFR Part 27). Staff determined that this project would fall into the category of medium vulnerability. Staff therefore proposes that certain security measures be implemented but does not propose that the project owner conduct its own vulnerability assessment.

These security measures include perimeter fencing and breach detectors, alarms, site access procedures for employees and vendors, site personnel background checks, and law enforcement contacts in the event of a security breach. Site access for vendors shall be strictly controlled. Consistent with current state and federal regulations governing the transport of hazardous materials, hazardous materials vendors will have to maintain their transport vehicle fleet and employ only properly licensed and trained drivers. The project owner will be required, through the use of contractual language with vendors, to ensure that vendors supplying hazardous materials strictly adhere to the U.S. DOT requirements for hazardous materials vendors to prepare and implement security plans (as per 49 CFR 172.802) and to ensure that all hazardous materials drivers are in compliance through personnel background security checks (as per 49 CFR Part 1572, Subparts A and B). The compliance project manager (CPM) may authorize modifications to these measures or may require additional measures in response to additional guidance provided by the U.S. Department of Homeland Security, the U.S. DOE, or the NERC, after consultation with both appropriate law enforcement agencies and the applicant.

CUMULATIVE IMPACTS AND MITIGATION

Staff analyzed the potential for the existence of cumulative impacts. A significant cumulative hazardous materials impact is defined as the simultaneous uncontrolled release of hazardous materials from multiple locations in a form (gas or liquid) that could cause a significant impact where the release of one hazardous material alone would not cause a significant impact. Existing locations that use or store gaseous or liquid hazardous materials, or locations where such facilities might likely be built, were both considered. The nearby area is comprised of agricultural lands, which frequently use ammonia as a fertilizer and therefore may have mobile ammonia tanks at various locations. Other than these tanks, staff found no existing or proposed facilities within a distance that could possibly contribute to a cumulative impact. Staff believes that while cumulative impacts are theoretically possible, they are not probable because of the many safeguards implemented to both prevent and mitigate an uncontrolled release.

The applicant's modeling of a worst-case release of aqueous ammonia from the proposed project site predicts that significant levels of ammonia vapors would not occur off-site and therefore no cumulative impacts would be expected even if a nearby mobile ammonia tank would experience an accidental release concurrent with that from the proposed HECA (HEI 2008c, Section 5.12.4). The applicant will develop and implement a hazardous materials handling program for HECA independent of any other projects considered for potential cumulative impacts. Staff believes that the facility, as proposed by the applicant and with the additional mitigation measures proposed by staff, poses a less than significant risk of accidental release that could result in off-site impacts. It is unlikely that an accidental release that has very low probability of occurrence (about one in one million per year) would independently occur at the HECA site and another site at the same time. Therefore, staff concludes that the facility would not contribute to a significant hazardous materials-related cumulative impact.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Staff concludes that construction and operation of the HECA project would be in compliance with all applicable laws, ordinances, regulations, and standards (LORS) regarding long-term and short-term project impacts in the area of hazardous materials management.

CONCLUSIONS

Staff's evaluation of the proposed project indicates that, with the proposed mitigation measures **HAZ-1** through **HAZ-10**, hazardous material use will pose no significant impact to the public. Staff's analysis also shows that there will be no significant cumulative impact. With adoption of the proposed conditions of certification, the proposed project will comply with all applicable LORS. In response to Health and Safety Code, section 25531 et seq., the applicant will be required to develop a Risk Management Plan (RMP). To ensure the adequacy of the RMP, staff's proposed conditions of certification require that the RMP be submitted for concurrent review by the Anaheim Fire Department and by Energy Commission staff. In addition, staff's proposed conditions of certification require the review and approval of the RMP by staff prior to the delivery of any hazardous materials to the facility. Other proposed conditions of certification address the issue of the transportation, storage, and use of aqueous ammonia, in addition to site security matters.

Staff recommends that the Energy Commission impose the proposed conditions of certification, presented herein, to ensure that the project is designed, constructed, and operated to comply with all applicable LORS and to protect the public from significant risk of exposure to an accidental ammonia release. If all mitigation proposed by the applicant and staff are required and implemented, the use, storage, and transportation of hazardous materials will not present a significant risk to the public.

Staff proposes ten conditions of certification mentioned throughout the text (above), and listed below. Condition of Certification **HAZ-1** ensures that no hazardous material would be used at the facility except as listed in **Appendix B** of the staff assessment, unless there is prior approval by the Energy Commission compliance project manager. Condition of Certification **HAZ-2** requires that an RMP be prepared and submitted prior to the delivery of aqueous ammonia.

Staff believes that an accidental release of aqueous ammonia during transfer from the delivery tanker to the storage tank is the most probable accident scenario and therefore proposes Condition of Certification (**HAZ-3**) requiring the development of a safety management plan for the delivery of all liquid hazardous materials, including aqueous ammonia. The development of a safety management plan addressing the delivery of all liquid hazardous materials during construction, commissioning, and operations will further reduce the risk of any accidental release not addressed by the proposed spill-prevention mitigation measures and the required RMP. This plan would additionally prevent the mixing of incompatible materials that could result in toxic vapors. Condition of Certification **HAZ-4** requires that the aqueous ammonia storage tank be designed to certain specifications. The transportation of hazardous materials is addressed in Conditions of Certification **HAZ-5** and **HAZ-6**. Site security during both the construction and operations phases is addressed in Conditions of Certification **HAZ-7** and **HAZ-8.** The project owner would also be required by **HAZ-9** to purchase the nearest residence located approximately 370 feet northwest of the project site, ensure that the residents have left, and prohibit anyone from residing there in the future. Staff believes that this residence's proximity to the facility would place any resident at a significant risk of harm if allowed to continue to reside at that location.

The applicant has also proposed several Conditions of Certification. Those that are accepted by staff can be found in proposed Condition of Certification **HAZ-10**.

PROPOSED CONDITIONS OF CERTIFICATION

HAZ-1 The project owner shall not use any hazardous materials not listed in Appendix B, below, or in greater quantities or strengths than those identified by chemical name in Appendix B, below, unless approved in advance by the Compliance Project Manager (CPM).

Verification: The project owner shall provide to the CPM, in the Annual Compliance Report, a list of hazardous materials contained at the facility.

HAZ-2 The project owner shall concurrently provide a Hazardous Materials Business Plan (HMBP), a Spill Prevention, Control, and Countermeasure Plan (SPCC), a Process Safety Management Plan (PSMP) that includes a Hazard and Operability (HAZOP) Analysis specifically for the use and storage of aqueous ammonia, methanol, and liquid oxygen, and a Risk Management Plan (RMP) specifically for the use and storage of aqueous ammonia, methanol, and liquid oxygen and prepared pursuant to the California Accidental Release Program (CalARP) to the Kern County EHSD and the CPM for review. After receiving comments from the Kern County EHSD and the CPM, the project owner shall reflect all recommendations in the final documents. Copies of the final plans shall then be provided to the Kern County EHSD for information and to the CPM for approval.

Verification: At least thirty (30) days prior to receiving any hazardous material on the site for commissioning or operations, the project owner shall provide a copy of a final Hazardous Materials Business Plan, Spill Prevention, Control, and Countermeasure Plan, a Process Safety Management Plan, and a Risk Management

Plan to the CPM for approval. At least thirty (30) days prior to delivery of aqueous ammonia to the site, the project owner shall provide the final RMP to the Certified Unified Program Agency for information and to the CPM for approval.

HAZ-3 The project owner shall develop and implement a Safety Management Plan for delivery of aqueous ammonia and other liquid and gaseous hazardous materials by tanker truck. The plan shall include procedures, protective equipment requirements, training, and a checklist. It shall also include a section describing all measures to be implemented to prevent mixing of incompatible hazardous materials including provisions to maintain lockout control by a power plant employee not involved in the delivery or transfer operation. It shall also describe the type, number, locations, and detection limits of hazardous gas monitors for ammonia, carbon monoxide, hydrogen sulfide, and sulfur dioxide. This plan shall be applicable during commissioning and operation of the power plant.

Verification: At least thirty (30) days prior to the delivery of any liquid or gaseous hazardous material to the facility for the purposes of commissioning, the project owner shall provide the Safety Management Plan as described above to the CPM for review and approval.

HAZ-4 The aqueous ammonia storage facility shall be designed to either the ASME Pressure Vessel Code and ANSI K61.6 or to API 620. In either case, the storage tank shall be protected by a secondary containment basin that will utilize floating balls to minimize surface area vapor losses, shall be equipped with an underground containment vault, and shall be capable of holding 125% of the storage volume or the storage volume plus the volume associated with 24 hours of rain assuming the 25-year storm. The final design drawings and specifications for the ammonia storage tank and secondary containment basin shall be submitted to the CPM.

Verification: At least sixty (60) days prior to delivery of aqueous ammonia to the facility, the project owner shall submit final design drawings and specifications for the ammonia storage tank and secondary containment basin to the CPM for review and approval.

HAZ-5 The project owner shall direct all vendors delivering aqueous ammonia to the site to use only tanker truck transport vehicles which meet or exceed the specifications of DOT Code MC-307. The project owner shall provide this direction in a letter to the vendor(s) at least thirty (30) days prior to the receipt of aqueous ammonia on site.

Verification: At least thirty (30) days prior to receipt of aqueous ammonia on site, the project owner shall submit copies of the notification letter to supply vendors indicating the transport vehicle specifications to the CPM for review and approval.

HAZ-6 At least thirty (30) days prior to receipt of any hazardous materials on site, the project owner shall direct all vendors delivering any hazardous material to the site to use only the route approved by the CPM. Trucks will travel from Bakersfield via Stockdale Road and Dairy Road to the plant site. The project owner shall obtain approval of the CPM if an alternate route is desired.

Verification: At least thirty (30) days prior to receipt of any hazardous materials on site, the project owner shall submit to the CPM for review and approval copies of notices to hazardous materials vendors describing the required transportation route.

HAZ-7 Prior to commencing construction, a site-specific Construction Site Security Plan for the construction phase shall be prepared and made available to the CPM for review and approval. The Construction Security Plan shall include the following:

1. perimeter security consisting of fencing enclosing the construction area;
2. security guards;
3. site access control consisting of a check-in procedure or tag system for construction personnel and visitors;
4. written standard procedures for employees, contractors and vendors when encountering suspicious objects or packages on site or off site;
5. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency; and
6. Evacuation procedures.

Verification: At least thirty (30) days prior to commencing construction, the project owner shall notify the CPM that a site-specific Construction Security Plan is available for review and approval.

HAZ-8 The project owner shall also prepare a site-specific security plan for the commissioning and operational phases that will be available to the CPM for review and approval. The project owner shall implement site security measures that address physical site security and hazardous materials storage. The level of security to be implemented shall not be less than that described below (as per NERC 2002).

The Operation Security Plan shall include the following:

1. permanent full perimeter fence or wall, at least 8 feet high;
2. main entrance security gate, either hand operated or motorized;
3. evacuation procedures;
4. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency;
5. written standard procedures for employees, contractors, and vendors when encountering suspicious objects or packages on site or off site;
6. A. a statement (refer to sample, **Attachment A**), signed by the project owner certifying that background investigations have been conducted on all project personnel. Background investigations shall be restricted

to determine the accuracy of employee identity and employment history and shall be conducted in accordance with state and federal laws regarding security and privacy;

B. a statement(s) (refer to sample, **Attachment B**), signed by the contractor or authorized representative(s) for any permanent contractors or other technical contractors (as determined by the CPM after consultation with the project owner), that are present at any time on the site to repair, maintain, investigate, or conduct any other technical duties involving critical components (as determined by the CPM after consultation with the project owner) certifying that background investigations have been conducted on contractors who visit the project site;

7. site access controls for employees, contractors, vendors, and visitors;

8. a statement(s) (refer to sample, **Attachment C**), signed by the owners or authorized representative of hazardous materials transport vendors, certifying that they have prepared and implemented security plans in compliance with 49 CFR 172.802, and that they have conducted employee background investigations in accordance with 49 CFR Part 1572, subparts A and B;

9. closed circuit TV (CCTV) monitoring system, recordable, and viewable in the power plant control room and security station (if separate from the control room) capable of viewing, at a minimum, the main entrance gate and the ammonia storage tank; and

10. additional measures to ensure adequate perimeter security consisting of either:

    a. security guard(s) present 24 hours per day, 7 days per week;

    <u>or</u>

    b. power plant personnel on site 24 hours per day, 7 days per week, and **all** of the following:

        1. the CCTV monitoring system required in item 9, above, shall include cameras able to pan, tilt, and zoom; that have low-light capability, are recordable, and are able to view 100% of the perimeter fence, the ammonia storage tank, the outside entrance to the control room, and the front gate from a monitor in the power plant control room; **and**

        2. perimeter breach detectors **<u>or</u>** on-site motion detectors.

The project owner shall fully implement the security plans and obtain CPM approval of any substantive modifications to those security plans. The CPM may authorize modifications to these measures, or may require additional measures such as protective barriers for critical power plant components or cyber security measures depending upon circumstances unique to the facility or in response to industry-related standards, security concerns, or additional guidance provided by the U.S. Department of Homeland Security, the U.S. Department of Energy, or the North American Electrical Reliability Council, after consultation with both appropriate law enforcement agencies and the applicant.

<u>Verification:</u> At least thirty (30) days prior to the initial receipt of hazardous materials on site, the project owner shall notify the CPM that a site-specific operations site security plan is available for review and approval. In the annual compliance report, the project owner shall include a statement that all current project employee and appropriate contractor background investigations have been performed and that updated certification statements have been appended to the operations security plan. In the annual compliance report, the project owner shall include a statement that the operations security plan includes all current hazardous materials transport vendor certifications for security plans and employee background investigations.

HAZ-9 The project owner shall purchase the nearest residence located approximately 370 feet northwest of the project site and prohibit any persons from living at that location. The project owner shall provide a letter to the CPM at least thirty (30) days prior to site mobilization that the purchase is complete and that persons living at that residence have vacated the premises.

<u>Verification:</u> At least thirty (30) days prior to site mobilization, the project owner shall provide a letter to the CPM indicating that the residence is purchased, that no one resides there, and that no on is allowed to reside there.

HAZ-10 The project owner shall prepare management plans and implement the following programs as proposed by the applicant in section 5.12.5 of the Revised AFC:

1. Vehicle Fueling Plan: The following measures shall be implemented related to fueling and maintenance of vehicles and equipment:

- No smoking, open flames, or welding shall be allowed in the fueling/services areas.
- Servicing and fueling of vehicles and equipment shall occur only in designated areas.
- Fuel storage tanks shall have secondary containment.
- Fueling service and maintenance shall be conducted only by authorized personnel.
- Refueling shall be conducted only with approved pumps, hoses, and nozzles.
- All disconnected hoses shall be handled in a manner to prevent residual fuel and fluids from being released into the environment.
- Catch-pans shall be placed under equipment/hose connections to catch potential spills during fueling and servicing.

- Service trucks shall be provided with fire extinguishers and spill containment equipment, such as absorbents, shovels, and containers.
- Service trucks shall not remain on the job site after fueling and service are complete.

2. Bulk Hazardous Materials Management Plan: Bulk hazardous materials shall be managed as described below:

- Bulk chemical storage tanks shall be equipped with a local level gauge and automated level instrumentation. To prevent overfilling, a high level alarm shall sound at the local common alarm panel if the storage tank reached an abnormally high-level, and be interlocked to shut down the metering pump.
- Sodium hydroxide shall be stored on site within one large, carbon-steel Above Ground Storage Tank (AST) and one waste tank (60,000 gallons total). Both tanks shall be equipped with secondary containment, capable of holding 110% of the tank volume (100% of sodium hydroxide tank plus an allowance for rainwater for a 24-hour, 25-year storm event). Associated transfer pumps and piping shall have secondary containment to collect any potential spills. Piping secondary containment shall also be equipped with liquid detectors to identify leaks.
- Sulfuric acid and sodium hypochlorite shall be stored at the Project Site in quantities of 14,000 gallons and 7,000 gallons, respectively. Both substances shall be stored in ASTs of compatible material. The storage tanks shall be equipped with secondary containment, capable of storing the entire volume of the tank. The tanks shall also be equipped with liquid detectors to identify the presence of any liquid substance within the secondary annular space. Additionally, the area surrounding the tanks shall be constructed and coated to prevent its corrosion or deformation from an accidental chemical spill.
- The sulfuric acid and sodium hypochlorite delivery systems shall be equipped with flow meters and automatic shutdown capabilities. Transfer pumps and piping shall have secondary containment to collect any potential spills.
- The 2,000-gallon diesel storage tank shall be equipped with secondary containment capable of holding 110% of the tank volume (100% of diesel tank plus an allowance for rainwater for a 24-hour, 25-year storm event).
- The 200 gallons of lubricating oil shall be stored in a tank that shall be equipped with a secondary containment capable of holding 100% of the tank volume. Liquid detection equipment shall be installed to detect any potential leaks generated and collected in the secondary containment annular space.
- Hydrogen shall be stored on site (29,000 scf) within a multi-tube trailer and shall be monitored and controlled through the use of flow meters and pressure monitors. The hydrogen system shall also be equipped with pressure relief valves and automatic shutdown.

- Carbon dioxide for fire suppression and purging (50,000 scf) shall be stored on site within large pressurized cylinders and/or tanks, which shall be equipped with pressure sensors and automatic shutdown controls, and pressure relief valves.
- Liquid oxygen shall be stored in a large aboveground vessel and the maximum amount of 1,100-tons of liquid oxygen shall not be exceeded. Pressure relief valves and automatic shutdown equipment shall be provided for the oxygen delivery system.
- Not greater than 150,000 gallons of degassed molten sulfur shall be stored on site within two sulfur storage pits. Both sulfur storage pits shall be constructed of compatible material, shall be structurally sound (free of any cracks or fissures), and shall be equipped with pressure-monitoring equipment and ventilation lines. In addition, sulfur-loading equipment shall have a vapor recovery system to control fugitive emissions by returning displaced vapors to the SRU.
- Methanol in the process unit shall be stored in a single 300,000-gallon AST with secondary containment. An additional 250,000 gallons of methanol will also be contained within process vessels, equipment, and piping of the of AGR unit. This process inventory shall be kept geographically remote from the 300,000-gallon AST, and a pump and isolation valve shall be placed on the piping between the storage tank and the AGR unit isolating the AST and AGR unit. The tanks shall also be equipped with leak detectors to identify the presence of any liquid accumulation below the tank bottom or in the containment area. The methanol delivery system shall be equipped with a flow meter and automatic shutdown capabilities. The methanol transfer pump and piping shall have secondary containment to collect any potential spills.
- Sodium phosphate shall be contained in an AST located at the indoor chemical storage area. The sodium phosphate ASTs shall be equipped with secondary containment and leak detectors to detect the presence of a rupture.
- The closed-loop cooling system of the process equipment that contains propylene glycol as a heat transfer fluid shall be equipped with leak detection equipment.

The project owner shall provide to the CPM for review and approval a copy of the Vehicle Fueling Plan and the Bulk Hazardous Materials Management Plan.

Verification: At least thirty (30) days prior to site mobilization, the project owner shall provide the Vehicle Fueling Plan to the CPM for review and approval. At least thirty (30) days prior to the initial receipt of any hazardous material on-site for commissioning, the project owner shall provide the Bulk Hazardous Materials Management Plan to the CPM for review and approval.

SAMPLE CERTIFICATION (Attachment A)

Affidavit of Compliance for Project Owners

I,

____

(Name of person signing affidavit)(Title)

do hereby certify that background investigations to ascertain the accuracy of the identity and employment history of all employees of

____

(Company name)

for employment at

____

(Project name and location)

have been conducted as required by the California Energy Commission Decision for the above-named project.

____

(Signature of officer or agent)

Dated this ____________________ day of ____________________, 20 _______.

THIS AFFIDAVIT OF COMPLIANCE SHALL BE APPENDED TO THE PROJECT SECURITY PLAN AND SHALL BE RETAINED AT ALL TIMES AT THE PROJECT SITE FOR REVIEW BY THE CALIFORNIA ENERGY COMMISSION COMPLIANCE PROJECT MANAGER.

SAMPLE CERTIFICATION (Attachment B)

Affidavit of Compliance for Contractors

I,

____
(Name of person signing affidavit)(Title)

do hereby certify that background investigations to ascertain the accuracy of the identity and employment history of all employees of

____
(Company name)

for contract work at

____
(Project name and location)

have been conducted as required by the California Energy Commission Decision for the above-named project.

____
(Signature of officer or agent)

Dated this ____________________ day of ____________________, 20 _______.

THIS AFFIDAVIT OF COMPLIANCE SHALL BE APPENDED TO THE PROJECT SECURITY PLAN AND SHALL BE RETAINED AT ALL TIMES AT THE PROJECT SITE FOR REVIEW BY THE CALIFORNIA ENERGY COMMISSION COMPLIANCE PROJECT MANAGER.

SAMPLE CERTIFICATION (Attachment C)

Affidavit of Compliance for Hazardous Materials Transport Vendors

I,

____

(Name of person signing affidavit)(Title)

do hereby certify that the below-named company has prepared and implemented security plans in conformity with 49 CFR 172.880 and has conducted employee background investigations in conformity with 49 CFR 172, subparts A and B,

____

(Company name)

for hazardous materials delivery to

____

(Project name and location)

as required by the California Energy Commission Decision for the above-named project.

____

(Signature of officer or agent)

Dated this ____________________ day of ____________________, 20 _______.

THIS AFFIDAVIT OF COMPLIANCE SHALL BE APPENDED TO THE PROJECT SECURITY PLAN AND SHALL BE RETAINED AT ALL TIMES AT THE PROJECT SITE FOR REVIEW BY THE CALIFORNIA ENERGY COMMISSION COMPLIANCE PROJECT MANAGER.

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HAZARDOUS MATERIALS
Appendix A

Basis for Staff’s Use of 75 Parts Per Million Ammonia Exposure Criteria

BASIS FOR STAFF'S USE OF 75 Parts Per Million AMMONIA EXPOSURE CRITERIA

Staff uses a health-based airborne concentration of 75 parts per million (PPM) to evaluate the significance of impacts associated with potential accidental releases of ammonia. While this level is not consistent with the 200-ppm level used by the U.S. Environmental Protection Agency and the California Environmental Protection Agency in evaluating such releases pursuant to the Federal Risk Management Program and State Accidental Release Program, it is appropriate for use in staff's analysis of the proposed project. The Federal Risk Management Program and the State Accidental Release Program are administrative programs designed to address emergency planning and ensure that appropriate safety management practices and actions are implemented in response to accidental releases. However, the regulations implementing these programs do not provide clear authority to require design changes or other major changes to a proposed facility. The preface to the Emergency Response Planning Guidelines states that "these values have been derived as planning and emergency response guidelines, **not** exposure guidelines, they do not contain the safety factors normally incorporated into exposure guidelines. Instead they are estimates, by the committee, of the thresholds above which there would be an unacceptable likelihood of observing the defined effects." It is staff's contention that these values apply to healthy adult individuals and are levels that should not be used to evaluate the acceptability of avoidable exposures for the entire population. While these guidelines are useful in decision making in the event that a release has already occurred (for example, prioritizing evacuations), they are not appropriate for and are not binding on discretionary decisions involving proposed facilities where many options for mitigation are feasible. California Environmental Quality Act requires permitting agencies making discretionary decisions to identify and mitigate potentially significant impacts through feasible changes or alternatives to the proposed project.

Staff has chosen to use the National Research Council's 30-minute Short Term Public Emergency Limit (STPEL) for ammonia to determine the potential for significant impact. This limit is designed to apply to accidental unanticipated releases and subsequent public exposure. Exposure at this level should not result in serious effects but would result in "strong odor, lacrimation, and irritation of the upper respiratory tract (nose and throat), but no incapacitation or prevention of self-rescue." It is staff's opinion that exposures to concentrations above these levels pose significant risk of adverse health impacts on sensitive members of the general public. It is also staff's position that these exposure limits are the best available criteria to use in gauging the significance of public exposures associated with potential accidental releases. It is, further, staff's opinion that these limits constitute an appropriate balance between public protection and mitigation of unlikely events and are useful in focusing mitigation efforts on those release scenarios that pose real potential for serious impacts on the public. Table 1 provides a comparison of the intended use and limitations associated with each of the various criteria that staff considered in arriving at the decision to use the 75-ppm STPEL.

HAZARDOUS MATERIALS Appendix A Table-1
Acute Ammonia Exposure Guidelines

Guideline	Responsible Authority	Applicable Exposed Group	Allowable Exposure Level	Allowable* Duration of Exposures	Potential Toxicity at Guideline Level/Intended Purpose of Guideline
IDLH[2]	)SH	Workplace standard used to identify appropriate respiratory protection.	300 ppm	30 minutes	Exposure above this level requires the use of “highly reliable” respiratory protection and poses the risk of death, serious irreversible Injury, or impairment of the ability to escape.
IDLH/10[1]	EPA, NIOSH	Work place standard adjusted for general population factor of 10 for variation in sensitivity	30 ppm	30 minutes	Protects nearly all segments of general population from irreversible effects.
STEL[2]	NIOSH	Adult healthy male workers	35 ppm	15 minutes, 4 times per 8-hour day	No toxicity, including avoidance of irritation.
EEGL[3]	NRC	Adult healthy workers, military personnel	100 ppm	Generally less than 60 minutes	Significant irritation, but no impact on personnel in performance of emergency work; no irreversible health effects in healthy adults. Emergency conditions one-time exposure.
STPEL[4]	NRC	Most members of general population	50 ppm 75 ppm 100 ppm	60 minutes 30 minutes 10 minutes	Significant irritation, but protects nearly all segments of general population from irreversible acute or late effects. One-time accidental exposure.
TWA[2]	NIOSH	Adult healthy male workers	25 ppm	8 hours	No toxicity or irritation on continuous exposure for repeated 8-hour work shifts.
ERPG-2[5]	AIHA	Applicable only to emergency response planning for the general population (evacuation) (not intended as exposure criteria) (see preface attached)	200 ppm	60 minutes	Exposures above this level entail** unacceptable risk of irreversible effects in healthy adult members of the general population (no safety margin).

1) (EPA 1987) 2) (NIOSH 1994) 3) (NRC 1985) 4) (NRC 1972) 5) (AIHA 1989)

* The (NRC 1979), (WHO 1986), and (Henderson and Haggard 1943) all conclude that available data confirm the direct relationship to increases in effect with both increased exposure and increased exposure duration.

** The (NRC 1979) describes a study involving young animals, which suggests greater sensitivity to acute exposure in young animals. The WHO (1986) warned that the young, elderly, asthmatics, those with bronchitis, and those that exercise should also be considered at increased risk based on their demonstrated greater susceptibility to other non-specific irritants.

REFERENCES FOR HAZARDOUS MATERIALS APPENDIX A, TABLE 1

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ABBREVIATIONS FOR HAZARDOUS MATERIALS APPENDIX A, TABLE 1

ACGIH, American Conference of Governmental and Industrial Hygienists
AIHA, American Industrial Hygienists Association
EEGL, Emergency Exposure Guidance Level
EPA, Environmental Protection Agency
ERPG, Emergency Response Planning Guidelines
IDLH, Immediately Dangerous to Life and Health Level
NIOSH, National Institute of Occupational Safety and Health
NRC, National Research Council
STEL, Short Term Exposure Limit
STPEL, Short Term Public Emergency Limit
TLV, Threshold Limit Value
WHO, World Health Organization

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HAZARDOUS MATERIALS
Appendix B

Hazardous Materials Proposed for Use at the HECA

HAZARDOUS MATERIALS Appendix B

Hazardous Materials Proposed for Use and Storage On-site at the HECA

Material	CAS No.	Application	Hazardous Characteristics	Maximum Quantity On Site
Ammonium Lignosulfonate		Slurry prep bldg for maintaining % solids in slurry	Health: mild irritant Physical:	63,000 gallons
Aqueous Ammonia 19% Solution	7664-41-7	Emissions control (SCR), gasifier pH control	Health: irritation to permanent damage from inhalation, ingestion, and skin contact Physical: reactive, vapor is combustible	20,000 gallons
Boiler Feedwater Chemicals (e.g., Carbonic Dihydrazide, Morpholine, Cyclohexamine, Sodium Sulfite)		Boiler feedwater pH/corrosion / dissolved oxygen/biocide control	Health: Physical: corrosive	< 500 gallons
Chemical Reagents (acids/bases/standards)		Lab	Health: Physical: corrosive, reactive	< 5 gallons
Combustion Turbine Wash Chemicals (specialty detergents and surfactants)		Combustion turbine cleaning	Health: toxic Physical: irritant	Intermittent use/cleaning by contractor
Compressed Carbon Dioxide Gas		Generator purging and fire protection	Health: asphyxiant Physical:	50,000 standard cubic feet for purging
Compressed Gases (Ar, He, H2)		Lab	Health: Physical: ignitable	Minimal
Cooling Water Chemical Additives (e.g., Magnesium Nitrate, Magnesium Chloride)		Corrosion inhibitor/biocides	Health: mild irritant, mildly toxic Physical:	< 500 gallons
CTG and HRSG Cleaning Chemicals (e.g., HCl, Citric Acid, EDTA Chelant, Sodium Nitrate)		HRSG chemical cleaning	Health: toxic Physical: reactive	Intermittent cleaning requirement/ temp storage only
Diesel Fuel	Mixture	Emergency generator/fire	Health: Low-toxicity Physical: Flammable liquid	2,000 gallons

		water pump fuel		
Diethylene Glycol Monobutyl Ether (Industrial Cleaner)		Routine cleaning, degreasing, oxygen pipeline cleaning	Health: toxic, mild irritant	None
Flammable/Hazardous Gases (H_2, CO, H_2S), Syngas and Hydrogen-Rich Gas		Primary power generation fuel	Health: toxic Physical: ignitable	In process quantities only, no storage on site
Hydrogen	1333-74-0	STG & CTG generator cooling	Health: low toxicity Physical: ignitable	29,000 standard cubic feet
Methanol		Gasifier startup-fuel, AGR solvent make-up	Health: Physical: ignitable	550,000 gallons
Methyldiethanol (40%)		Solvent for sulfur removal	Health: mild irritant, mildly toxic Physical:	220,000 pounds
Miscellaneous Industrial Gases – Acetylene, Oxygen, Other welding Gases, Analyzer Calibration Gases		Maintenance welding/ instrumentation calibration	Health: toxic Physical: ignitable	Minimal
Molten Sulfur		By-product for sale	Physical: ignitable, reactive	150,000 gallons
Natural Gas	74-82-8	Startup/backup/ auxiliary fuel	Health: Asphyxiant. Effects are due to lack of oxygen. Physical: flammable gasses	Utility supply on demand via pipeline
Nitrogen	7727-37-9	Syngas fuel diluent for NOx control, inert gas	Health: asphyxiant	50 tons
Oxygen (95%), Liquid		Gasification, SRU	Health: Physical: oxidizer	1,200 tons
Paint, Thinners, Solvents, Adhesives, etc.		Shop/warehouse	Health: toxic Physical: ignitable	< 20 gallons
Propylene Glycol (100%)	57-55-6	Heat transfer fluid	Health: mild irritant Physical: combustible	< 300 gallons
Propylene Glycol (45%)	57-55-6	Heat transfer fluid	Health: mild irritant Physical: combustible	25,000 gallons
Sodium Bisulfite	7631-90-5	Raw water treatment	Health: irritant, mildly toxic Physical: corrosive	< 500 gallons
Sodium Hypochlorite	7681-52-9	Raw water treatment and cooling tower biological control	Health: toxic and corrosive Physical: corrosive, reactive	7,000 gallons
Sodium Hydroxide (5% - 50%)	1310-73-2	Plant wastewater ZLD, sour water treatment, gasification,	Health: causes eye and skin burns, hygroscopic, may cause severe respiratory tract irritation with possible burns,	60,000 gallons

		caustic scrubber	hazardous if ingested Physical: corrosive	
Sodium Phosphate		Raw water treatment, gasification, plant wastewater ZLD	Health: irritant, mildly toxic	1,500 gallons
Sulfuric Acid	7664-93-9	Plant wastewater ZLD	Health: irritant to eyes, poisonous if inhaled, extreme irritant, corrosive, and toxic to tissue Physical: corrosive	2,000 gallons
Sulfuric Acid	7664-93-9	Cooling water, BFW pH control	Health: high toxicity Physical: corrosive, water reactive	12,000 gallons
Water Treatment Chemicals		Raw water, demineralized water, and cooling water treatment	Health: irritant, mildly toxic	< 500 gallons

Source: HEI 2008c,Tables 5.12-3 & 5.12-4

a. Reportable quantities for a pure chemical, per the Comprehensive Environmental Response, Compensation, and Liability Act.

NOISE AND VIBRATION

Erin Bright

SUMMARY OF CONCLUSIONS

California Energy Commission staff concludes that the Hydrogen Energy California Project can be built and operated in compliance with all applicable noise and vibration laws, ordinances, regulations, and standards and, if built in accordance with the conditions of certification proposed below, would produce no significant adverse noise impacts on people within the affected area, either direct, indirect, or cumulative.

INTRODUCTION

The construction and operation of any power plant creates noise, or unwanted sound. The character and loudness of this noise, the times of day or night that it is produced, and the proximity of the facility to sensitive receptors combine to determine whether the facility would meet applicable noise control laws and ordinances and whether it would cause significant adverse environmental impacts. In some cases, vibration may be produced as a result of power plant construction practices, such as blasting or pile driving. The groundborne energy of vibration has the potential to cause structural damage and annoyance.

The purpose of this analysis is to identify and examine the likely noise and vibration impacts from the construction and operation of the Hydrogen Energy California Project (HECA) and to recommend procedures to ensure that the resulting noise and vibration impacts would be adequately mitigated to comply with applicable laws, ordinances, regulations, and standards (LORS) and to avoid creation of significant adverse noise or vibration impacts. For an explanation of technical terms and acronyms employed in this section, please refer to **Noise Appendix A** immediately following.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Noise Table 1
Laws, Ordinances, Regulations, and Standards

Applicable Law	Description
Federal (OSHA): 29 U.S.C. § 651 et seq.	Protects workers from the effects of occupational noise exposure.
State (Cal/OSHA): Cal. Code Regs., tit. 8, §§ 5095–5099	Protects workers from the effects of occupational noise exposure.
Local Kern County General Plan Noise Element Policies (5)(a) and (5)(b)	Policy (5) prohibits new noise-sensitive land uses in noise-impacted areas unless effective mitigation measures are incorporated to (a) reduce noise levels in outdoor activity areas to 65 dBA L_{dn} or less, and (b) reduce interior noise levels to 45 dBA L_{dn} or less.

Applicable Law	Description
Kern County Code of Ordinance, Chapter 8.36 (“Noise Control”)	Subsection H limits hours of noisy construction work.

FEDERAL

Under the Occupational Safety and Health Act of 1970 (29 USC § 651 et seq.), the Department of Labor, Occupational Safety and Health Administration (OSHA) has adopted regulations designed to protect workers against the effects of occupational noise exposure (29 CFR § 1910.95). These regulations list permissible noise exposure levels as a function of the amount of time during which the worker is exposed (see **NOISE Appendix A, Table A4** immediately following this section). The regulations further specify a hearing conservation program that involves monitoring the noise to which workers are exposed, assuring that workers are made aware of overexposure to noise, and periodically testing the workers’ hearing to detect any degradation.

There are no federal laws governing off-site (community) noise.

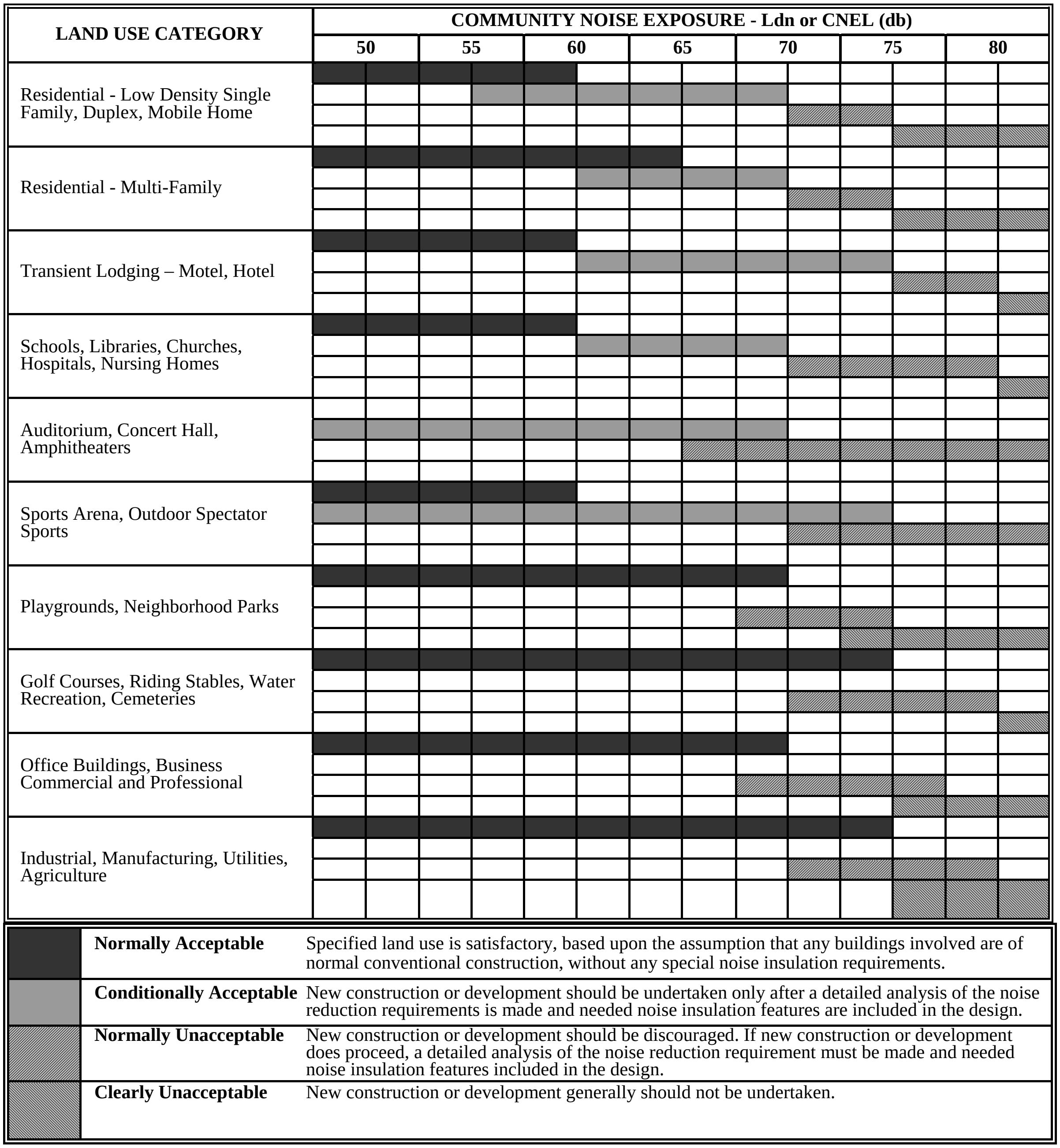
The only guidance available for evaluation of power plant vibration is guidelines published by the Federal Transit Administration (FTA) for assessing the impacts of groundborne vibration associated with construction of rail projects. These guidelines have been applied by other jurisdictions to assess groundborne vibration of other types of projects. The FTA-recommended vibration standards are expressed in terms of the “vibration level,” which is calculated from the peak particle velocity measured from groundborne vibration. The FTA measure of the threshold of perception is 65 VdB,[1] which correlates to a peak particle velocity of about 0.002 inches per second (in/sec). The FTA measure of the threshold of architectural damage for conventional sensitive structures is 100 VdB, which correlates to a peak particle velocity of about 0.2 in/sec.

STATE

California Government Code section 65302(f) encourages each local governmental entity to perform noise studies and implement a noise element as part of its General Plan. In addition, the California Office of Planning and Research has published guidelines for preparing noise elements, which include recommendations for evaluating the compatibility of various land uses as a function of community noise exposure. The State land use compatibility guidelines are listed in **Noise Table 2**.

[1] VdB is the common measure of vibration energy.

Noise Table 2
Land Use Compatibility for Community Noise Environment



Source: State of California General Plan Guidelines, Office of Planning and Research, June 1990.

The California Occupational Safety and Health Administration (Cal/OSHA) has promulgated Occupational Noise Exposure Regulations (Cal. Code Regs., tit. 8, §§ 5095–5099) that set employee noise exposure limits. These standards are equivalent to the federal OSHA standards (see the **Worker Safety and Fire Protection** section of this document, and **NOISE Appendix A, Table A4**).

LOCAL

Kern County General Plan Noise Element

Two policies enunciated in this noise element (Kern County 2007) impact the construction and operation of a project such as HECA. Policy (5)(a) prohibits new noise-sensitive land uses in noise-impacted areas unless effective mitigation measures are incorporated into the project design to reduce noise levels in outdoor activity areas to 65 dBA L_{dn} or less. Policy (5)(b) prohibits new noise-sensitive land uses in noise impacted areas unless effective mitigation measures are incorporated into the project design to reduce interior noise levels within living spaces or other noise sensitive interior spaces to 45 dBA L_{dn} or less.

Kern County Code of Ordinance

The Noise Control Ordinance (Kern County 2009) in Chapter 8.36 of the Kern County Code states that noise from construction should be limited to the following hours when construction takes place within 1,000 feet of a sensitive receptor:

- Weekdays 6:00 a.m. to 9:00 p.m.
- Weekends 8:00 a.m. to 9:00 p.m.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

California Environmental Quality Act

The California Environmental Quality Act (CEQA) requires that significant environmental impacts be identified and that such impacts be eliminated or mitigated to the extent feasible. Section XI of Appendix G of CEQA Guidelines (Cal. Code Regs., tit. 14, App. G) sets forth some characteristics that may signify a potentially significant impact. Specifically, a significant effect from noise may exist if a project would result in:

1. exposure of persons to, or generation of, noise levels in excess of standards established in the local General Plan or noise ordinance or applicable standards of other agencies;

2. exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels;

3. substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project; or

4. substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project.

The Energy Commission staff, in applying item 3 above to the analysis of this and other projects, has concluded that a potential for a significant noise impact exists where the noise of the project plus the background exceeds the background by 5 dBA or more at the nearest sensitive receptor.

Staff considers it reasonable to assume that an increase in background noise levels up to 5 dBA in a residential setting is insignificant; an increase of more than 10 dBA is considered significant. An increase between 5 and 10 dBA should be considered adverse, but may be either significant or insignificant, depending on the particular circumstances of the case.

Factors to be considered in determining the significance of an adverse impact as defined above include:

1. the resulting combined noise level;[2]
2. the duration and frequency of the noise;
3. the number of people affected;
4. the land use designation of the affected receptor sites; and
5. public concern or controversy as demonstrated at workshops or hearings or by correspondence.

Noise due to construction activities is usually considered to be insignificant in terms of CEQA compliance if:

- the construction activity is temporary;
- use of heavy equipment and noisy activities are limited to daytime hours; and
- all industry-standard noise abatement measures are implemented for noise-producing equipment.

Staff uses the above method and threshold to protect the most sensitive populations, including the minority population.

SETTING

HECA would be constructed on a 473 acre site located approximately 1.5 miles northwest of the town of Tupman in western Kern County. The project site and surrounding land are agricultural and residential (HEI 2009c, AFC §§ 2.1.5, 5.4.1.2).

The ambient noise regime in the project vicinity consists of wildlife and vehicular traffic. The nearest sensitive noise receptor is a residence located approximately 375 feet northwest of the project site (HEI 2009c, AFC §§ 5.5.1.3, 5.5.1.4, Table 5.4-1).

[2] For example, a noise level of 40 dBA would be considered quiet in many locations. A noise limit of 40 dBA would be consistent with the recommendations of the California Model Community Noise Control Ordinance for rural environments and with industrial noise regulations adopted by European jurisdictions. If the project would create an increase in ambient noise no greater than 10 dBA at nearby sensitive receptors, and the resulting noise level would be 40 dBA or less, the project noise level would likely be insignificant.

Ambient Noise Monitoring

In order to establish a baseline for comparison of predicted project noise to existing ambient noise, the applicant has presented the results of an ambient noise survey (HEI 2009c, AFC § 5.5.1.3; Tables 5.5-2 through 5.5-10). The survey was conducted March 2 through March 4, 2009, and monitored existing noise levels at the following locations, shown on **Noise and Vibration Figure 1**:

1. Measuring Location LT1: Near two residences (a single-family residence and a mobile home) located approximately 375 feet northwest of the project boundary (approximately 3,400 feet northwest of the power block at the project center). This represents the nearest sensitive receptor, the one most likely to be impacted by project noise. Long term (25-hour) monitoring showed ambient noise levels typical of a rural environment.

2. Measuring Location LT2: Near two single-family residences located approximately 1,400 feet east of the eastern project boundary (approximately 4,500 feet of the project center). Long term monitoring showed ambient noise levels typical of a rural environment, similar to those at measuring location LT1.

Noise Table 3 summarizes the ambient noise measurements at these sensitive receptors (HEI 2009c, AFC Tables 5.5-2 and 5.5-4):

Noise Table 3
Summary of Measured Ambient Noise Levels

Measurement Location	Measured Noise Levels, dBA		
	L_{eq} – Daytime[1]	L_{eq} – Nighttime[2]	L_{90} – Nighttime[3]
LT1: Northwest Residence	54	49	32
LT2: East Residence	56	51	30

Source: HEI 2009c, AFC Tables 5.5-2 and 5.5-4
[1] Staff calculations of average of 15 daytime hours
[2] Staff calculations of average of 9 nighttime hours
[3] Staff calculations of average of 4 consecutive quietest hours of the nighttime

DIRECT IMPACTS AND MITIGATION

Noise impacts associated with the project can be created by short-term construction activities and by normal long-term operation of the power plant.

Construction Impacts and Mitigation

Construction noise is usually considered a temporary phenomenon. Construction of the HECA project is expected to be typical of large scale power plant projects in terms of schedule, equipment used, and other types of activities (HEI 2009c, AFC § 5.5.2.1).

Compliance with LORS

There are no specific LORS limiting the loudness of construction noise in Kern County, but staff compares the projected noise levels with ambient levels (please see the following discussion under **CEQA Impacts**).

Noisy construction work would be allowed only during the daytime hours of 6:00 a.m. to 9:00 p.m. weekdays and 8:00 a.m. to 9:00 p.m. weekends in compliance with the Kern County Code. To ensure that these hours are, in fact, enforced, staff proposes Condition of Certification **NOISE-6**. Therefore, the noise impacts of HECA construction activities would comply with the noise LORS.

CEQA Impacts

Power Plant Site

To evaluate construction noise impacts, staff compares the projected noise levels to the ambient. Since construction noise typically varies continually with time, it is most appropriately measured by, and compared to, the L_{eq} (energy average) metric.

The Applicant has predicted the noise impacts of project construction on the nearest sensitive receptors (HEI 2009c, AFC § 5.5.2.1, Tables 5.5-12 and 5.5-13). Assuming peak construction activity, a maximum noise level of 91 dBA L_{eq} is estimated to occur at a distance of 50 feet from the acoustic center of the construction activity (most often the power block). Noise levels at the nearest receptor, LT1, are thus projected to reach 73 dBA L_{eq} when construction takes place near the project boundary. As seen in **Noise Table 4** below, this would equate to an increase of 19 dBA over daytime ambient noise levels at LT1 when construction activities take place near the project boundary, which could be significant. However, construction for the project is expected to take place closer to the center of the project site for the majority of project construction. Noise levels from construction when construction takes place at the project center would attenuate to 54 dBA L_{eq} at location LT1, which when combined with daytime ambient levels would result in an increase of only 3 dBA over the ambient level, a less than significant increase.

Similarly, the maximum construction noise level of 91 dBA L_{eq} would reach 62 dBA at LT2 when construction activities take place near the project's eastern boundary, resulting in an increase of 7 dBA over daytime ambient levels (as shown in **Noise Table 4**). When construction activities take place near the project center, construction noise levels attenuate to 51 dBA at LT2, a level below the daytime ambient level.

Given that construction near project boundaries would take place only for a short period of time, with the majority of construction taking place near the center of the project site, and that noisy construction activities would be limited to daytime hours, staff considers the noise effects of plant construction at both LT1 and LT2 to be less than significant.

To ensure the project construction would create less than significant adverse impacts at the most noise-sensitive receptors, in addition to Condition of Certification **NOISE-6**, staff proposes Conditions of Certification **NOISE-1** and **NOISE-2**, which would establish a notification process and a noise complaint process to resolve any complaints regarding construction noise.

Noise Table 4
Predicted Power Plant Construction Noise Impacts

Receptor	Highest Construction Noise Level[1] (dBA L_{eq})	Measured Existing Ambient[2] (dBA L_{eq})	Cumulative (dBA L_{eq})	Change (dBA)
LT1: Northwest Residence	73	54 daytime	73 daytime	+19 daytime
		49 nighttime	73 nighttime	+24 nighttime
LT2: East Residence	62	56 daytime	63 daytime	+7 daytime
		51 nighttime	62 nighttime	+11 nighttime

1 Source: HEI 2009c, AFC § 5.5.2.1, Table 5.5-13 and staff calculations
2 Source: HEI 2009c, AFC Tables 5.5-2 and 5.5-4, and staff calculations of average of daytime and nighttime hours.

Linear Facilities

Linear facilities include approximately 8 miles of new electrical transmission lines, eight miles of natural gas supply pipeline, 15 miles of raw water supply pipeline, seven miles of potable water supply pipeline, and four miles of pipeline transmitting carbon dioxide offsite for sequestration (HEI 2009c, AFC §§ 2.1.6, 2.6.1.10). A majority of the length of these linear facilities would extend past the project site boundaries. While the construction noise levels for the linears would be noticeable, construction on linears proceeds rapidly, so no particular area is exposed to noise for more than a few days.

Steam Blows

Typically, the loudest noise encountered during construction, inherent in building any project incorporating a steam turbine, is created by the steam blows. After erection and assembly of the feedwater and steam systems, the piping and tubing that comprises the steam path has accumulated dirt, rust, scale and construction debris such as weld spatter, dropped welding rods and the like. If the plant were started up without thoroughly cleaning out these systems, all this debris would find its way into the steam turbine, quickly destroying the machine.

In order to prevent this, before the steam system is connected to the turbine, the steam line is temporarily routed to the atmosphere. High pressure steam is then raised in a heat recovery steam generator (HRSG) or a boiler and allowed to escape to the atmosphere through the steam piping. This flushing action, referred to as a steam blow, is quite effective at cleaning out the steam system. A series of short steam blows, lasting two or three minutes each, is performed several times daily over a period of two or three weeks. At the end of this procedure, the steam line is connected to the steam turbine, which is then ready for operation.

These steam blows can produce noise as loud as 130 dBA at a distance of 100 feet. This would attenuate to about 93 dBA, an exceedingly disturbing level, at location LT1, the nearest residence. In order to minimize disturbance from steam blows, the applicant intends to equip steam blow piping with a silencer that will reduce noise levels by 20 to 30 dBA, or to a level of 63 to 73 dBA at the nearest residence, LT1 (HEI 2009c, AFC § 5.5.2.1, Table 5.5-14). This is still an annoying noise level; staff proposes that, in addition to the use of a steam blow silencer, all steam blows be performed only during restricted daytime hours in order to minimize annoyance to residents (see proposed Conditions of Certification **NOISE-6** and **NOISE-8** below).

Alternatively, the Applicant could elect to employ a new, quieter steam blow process, variously referred to as QuietBlow™ or Silentsteam™. This method utilizes lower pressure steam over a continuous period of approximately 36 hours. Resulting noise levels reach only about 80 dBA at 100 feet; noise levels at the nearest residence, LT1, would thus be about 49 dBA, below the ambient background noise levels.

Regardless of which steam blow process the Applicant chooses, staff proposes a notification process (see proposed Condition of Certification **NOISE-7** below) to make neighbors aware of impending steam blows.

Pile Driving

The applicant has stated that pile driving may be necessary for construction of HECA (HEI 2009c, AFC § 5.5.2.1). If pile driving is required for construction of the project, the noise from this operation could be expected to reach 101 dBA at a distance of 50 feet. Pile driving noise would thus be projected to reach levels of 64 dBA L_{eq} at location LT1, the nearest residential receptor (staff calculation). Added to the existing daytime ambient level of 54 dBA L_{eq}, this would combine to produce 64 dBA, an increase of 10 dBA over ambient noise levels (see **NOISE Table 5,** below). While this would produce a noticeable impact, staff believes that limiting pile driving to daytime hours, in conjunction with its temporary nature, would result in impacts tolerable to residents. Staff proposes condition of certification **NOISE-8** to ensure that pile driving noise would be limited to daytime hours.

Noise Table 5
Pile Driving Noise Impacts

Receptor	Pile Driving Noise Level (dBA L_{eq})	Daytime Ambient Noise Level (dBA L_{eq})	Cumulative Level (dBA)	Change (dBA)
LT1	64	54	64	+10
LT2	62	56	63	+9

1 Source: HEI 2009c, AFC Table 5.5-13, and staff calculations

Vibration

The only construction operation likely to produce vibration that could be perceived off site would be pile driving, should it be employed. Vibration attenuates rapidly; it is likely that no vibration would be perceptible at any appreciable distance from the project site. Staff therefore believes there would be no significant impacts from construction vibration.

Worker Effects

The applicant has acknowledged the need to protect construction workers from noise hazards and has recognized those applicable LORS that would protect construction workers (HEI 2009c, AFC § 5.5.2.5). To ensure that construction workers are, in fact, adequately protected, staff has proposed Condition of Certification **NOISE-3**, below.

Operation Impacts and Mitigation

The primary noise sources of HECA include the turbine generators, cooling tower, gasification process equipment, and various pumps, compressors and fans (HEI 2009c, AFC § 5.5.2.3). Staff compares the projected noise with applicable LORS. In addition, staff evaluates any increase in noise levels at sensitive receptors due to the project in order to identify any significant adverse impacts.

In addition to specifying the use of low-noise packages for equipment and components (such as the heat recovery steam generator system components), the applicant included the following noise mitigation measures in performing computer modeling of noise impacts from project operation (HEI 2009c, AFC § 5.5.2.3):

- Acoustical turbine enclosures;
- Reduced-noise cooling tower cells; and
- Stack silencers.

A detailed list of noise control design features for the project was provided in the Application for Certification (HEI 2009c, AFC Table 5.5-15).

Compliance with LORS

The applicant performed noise modeling to determine the project's noise impacts on sensitive receptors (HEI 2009c, AFC § 5.5.2.3, Appendix K). Project operating noise levels are expected to attenuate to no more than 44 dBA L_{dn} at receptors LT1 and LT2. This figure complies with the noise level limits specified in the Kern County General Plan Noise Element, as shown in **Noise Table 6**.

Noise Table 6
Plant Operating Noise LORS Compliance

Receptor	Kern County General Plan Noise Element	Projected Noise Level
LT1 (closest residence)	65 dBA L_{dn} daytime 45 dBA L_{dn} nighttime	44 dBA L_{dn}
LT2		44 dBA L_{dn}

Source: Kern County 2007 and HEI 2009c, AFC § 5.5.2.3, Table 5.5-17.

CEQA Impacts

Power plant noise is unique. Essentially, a power plant operates as a steady, continuous, broadband noise source, unlike the intermittent sounds that comprise the majority of the noise environment. As such, power plant noise contributes to, and becomes part of, the background noise level, or the sound heard when most intermittent noises cease. Where power plant noise is audible, it will tend to define the background noise level. For this reason, staff compares the projected power plant noise to the existing ambient background (L_{90}) noise levels at the affected sensitive receptors. If this comparison identifies a significant adverse impact, then feasible mitigation must be incorporated in the project to reduce or remove the impact.

For residential receptors, staff evaluates project noise emissions by comparing them with nighttime ambient background levels; this evaluation assumes that the potential for public annoyance from power plant noise is greatest at night when residents are trying to sleep. Nighttime ambient noise levels are typically lower than daytime levels; differences in background noise levels of 5 to 10 dBA are common. Staff believes it is prudent to average the lowest nighttime hourly background noise levels to arrive at a reasonable baseline for comparison with the project's predicted noise level.

Adverse impacts on residential receptors can be identified by comparing predicted power plant noise levels with the nighttime ambient background noise levels at the nearest sensitive residential receptors.

The applicant has predicted operational noise levels; they are summarized here in **Noise Table 7**.

Noise Table 7
Predicted Operational Noise Levels and CEQA

Receptor	Project Alone Operational Noise Level L_{eq} (dBA) [1]	Measured Existing Ambient, Average Nighttime L_{90} (dBA) [2]	Project Plus Ambient L_{90} (dBA)	Change in Ambient Level
LT1	38	32	39	+7
LT2	38	30	38	+8

[1] Source: HEI 2009c, AFC § Table 5.5-17; staff calculations
[2] Source: HEI 2009c, AFC Tables 5.5-2 and 5.5-4; and staff calculations of average of four quietest consecutive nighttime hours

Combining the ambient noise level of 32 dBA L_{90} at LT1 (**Noise Table 7**, above) with the project noise level of 38 dBA L_{eq} would result in a level of 39 dBA L_{90}, 7 dBA over the ambient. Combining the ambient noise level at LT2 with the project noise level would result in a level of 38 dBA L_{90}, 8 dBA over ambient. As described above (in **Method and Threshold for Determining Significance**), staff regards an increase between 5 dBA and 10 dBA as a potentially significant impact. However, the California Model Community Noise Control Ordinance recommendations specify a noise level of 40 dBA to be typical for rural environments. Given that the project would create an increase in ambient noise less than 10 dBA at the nearby receptors and the cumulative noise level (project plus ambient level) would be within the recommended noise level for rural environments (40 dBA), staff considerers the project noise levels at locations LT1 and LT2 to be less-than-significant.

To ensure these noise levels are not further exceeded, staff proposes Condition of Certification **NOISE-4**, below.

Tonal Noises

One possible source of disturbance would be strong tonal noises. Tonal noises are individual sounds (such as pure tones) that, while not louder than permissible levels, stand out in sound quality. The applicant can avoid the creation of annoying tonal (pure-tone) noises by balancing the noise emissions of various power plant features during plant design. To ensure that tonal noises do not cause annoyance, staff proposes Condition of Certification **NOISE-4**, below.

Linear Facilities

Natural gas, water and carbon dioxide piping would lie underground and would be silent during operation. Noise effects from the electrical interconnection line typically do not extend beyond the right-of-way easement of the line and would thus be inaudible to any receptors.

Vibration

Vibration from an operating power plant could be transmitted by two chief means; through the ground (groundborne vibration) and through the air (airborne vibration).

The operating components of the HECA project consist of a high-speed turbine generators and various pumps and fans. All of these pieces of equipment must be carefully balanced in order to operate; permanent vibration sensors are attached to the turbines and generators. Based on experience with numerous previous projects employing similar equipment, Energy Commission staff believes that ground borne vibration from HECA would be undetectable by any likely receptor.

Airborne vibration (low frequency noise) can rattle windows and objects on shelves and can rattle the walls of lightweight structures. None of the project equipment is likely to produce low frequency noise; this makes it highly unlikely that HECA would cause perceptible airborne vibration effects.

Worker Effects

The applicant has acknowledged the need to protect plant operating and maintenance workers from noise hazards and has committed to comply with applicable LORS (HEI 2009c, AFC § 5.5.2.5, Appendix K-2). Signs would be posted in areas of the plant with noise levels exceeding 85 dBA (the level that OSHA recognizes as a threat to workers' hearing), and hearing protection would be required. To ensure that plant operation and maintenance workers are, in fact, adequately protected, Energy Commission staff has proposed Condition of Certification **NOISE-5**, below.

CUMULATIVE IMPACTS AND MITIGATION

Section 15130 of the CEQA Guidelines (Cal. Code Regs., tit. 14) requires a discussion of cumulative environmental impacts. Cumulative impacts are two or more individual impacts that, when considered together, are considerable or that compound or increase other environmental impacts. The CEQA Guidelines require that the discussion reflect the severity of the impacts and the likelihood of their occurrence, but need not provide as much detail as the discussion of the impacts attributable to the project alone.

The applicant has identified one projects in the vicinity of HECA, a proposed dairy farm and milk production facility that may occupy plots to the west, north and east of the HECA project site (HEI 2009c, AFC § 5.5.3, Appendix J). Due to their distance from HECA and the nearby noise sensitive receptors and the fairly low on-site noise levels predicted for dairy farms, however, the project does not pose a potential for cumulative noise impacts.

FACILITY CLOSURE

In the future, upon closure of HECA, all operational noise from the project would cease, and no further adverse noise impacts from operation of HECA would be possible. The remaining potential temporary noise source is the dismantling of the structures and equipment and any site restoration work that may be performed. Since this noise would be similar to that caused by the original construction, it can be treated similarly. That is, noisy work could be performed during daytime hours, with machinery and equipment properly equipped with mufflers. Any noise LORS that were in existence at that time would apply. Applicable conditions of certification included in the Energy Commission decision would also apply unless modified.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that HECA, if built and operated in conformance with the proposed conditions of certification below, would comply with all applicable noise and vibration LORS and would produce no significant adverse noise impacts on people within the project area, including the minority population, directly, indirectly, or cumulatively.

PROPOSED CONDITIONS OF CERTIFICATION

NOISE-1 At least 15 days prior to the start of ground disturbance, the project owner shall notify all residents within one mile of the site, by mail or other effective means, of the commencement of project construction. At the same time, the project owner shall establish a telephone number for use by the public to report any undesirable noise conditions associated with the construction and operation of the project and include that telephone number in the above notice. If the telephone is not staffed 24 hours per day, the project owner shall include an automatic answering feature, with date and time stamp recording, to answer calls when the phone is unattended. This telephone number shall be posted at the project site during construction in a manner visible to passersby. This telephone number shall be maintained until the project has been operational for at least one year.

Verification: Prior to ground disturbance, the project owner shall transmit to the Compliance Project Manager (CPM) a statement, signed by the project owner’s project manager, stating that the above notification has been performed and describing the method of that notification, verifying that the telephone number has been established and posted at the site, and giving that telephone number.

NOISE COMPLAINT PROCESS

NOISE-2 Throughout the construction and operation of HECA, the project owner shall document, investigate, evaluate, and attempt to resolve all project-related noise complaints. The project owner or authorized agent shall:

- Use the Noise Complaint Resolution Form (below), or a functionally equivalent procedure acceptable to the CPM, to document and respond to each noise complaint;
- Attempt to contact the person(s) making the noise complaint within 24 hours;
- Conduct an investigation to determine the source of noise related to the complaint;
- Take all feasible measures to reduce the noise at its source if the noise is project related; and
- Submit a report documenting the complaint and the actions taken. The report shall include: a complaint summary, including final results of noise reduction efforts, and if obtainable, a signed statement by the complainant stating that the noise problem is resolved to the complainant's satisfaction.

Verification: Within five days of receiving a noise complaint, the project owner shall file a copy of the Noise Complaint Resolution Form with the CPM, documenting the resolution of the complaint. If mitigation is required to resolve a complaint, and the complaint is not resolved within a three-day period, the project owner shall submit an updated Noise Complaint Resolution Form when the mitigation is implemented.

NOISE-3 The project owner shall submit to the CPM for review and approval a noise control program and a statement, signed by the project owner's project manager, verifying that the noise control program will be implemented throughout construction of the project. The noise control program shall be used to reduce employee exposure to high noise levels during construction and also to comply with applicable OSHA and Cal/OSHA standards.

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall submit to the CPM the noise control program and the project owner's project manager's signed statement. The project owner shall make the program available to Cal/OSHA upon request.

NOISE RESTRICTIONS

NOISE-4 The project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the noise levels due to operation of the project alone will not exceed: an hourly average of 38 dBA, measured at or near monitoring locations LT1 (approximately 375 feet northwest of the project site boundary) or LT2 (approximately 1,400 feet east of the project site boundary).

No new pure-tone components shall be caused by the project. No single piece of equipment shall be allowed to stand out as a source of noise that draws legitimate complaints.

A. When the project first achieves a sustained output of 85% or greater of rated capacity, the project owner shall conduct a 25-hour community noise survey at monitoring location LT1, or at a closer location acceptable to the CPM. This survey during the power plant's full-load operation shall also include measurement of one-third octave band sound pressure levels to ensure that no new pure-tone noise components have been caused by the project.

   During the period of this survey, the project owner shall conduct a short term survey of noise at monitoring location LT2, or at closer locations acceptable to the CPM. The short-term noise measurements at this location shall be conducted during the nighttime hours of 10:00 p.m. to 7:00 a.m.

   The measurement of power plant noise for the purposes of demonstrating compliance with this condition of certification may alternatively be made at a location, acceptable to the CPM, closer to the plant (e.g., 400 feet from the plant boundary) and this measured level then mathematically extrapolated to determine the plant noise contribution at the affected residence. The character of the plant noise shall be evaluated at the affected receptor locations to determine the presence of pure tones or other dominant sources of plant noise.

B. If the results from the noise survey indicate that the power plant noise at the affected receptor sites exceeds the above values, mitigation measures shall be implemented to reduce noise to a level of compliance with these limits.

C. If the results from the noise survey indicate that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.

Verification: The survey shall take place within 30 days of the project first achieving a sustained output of 85% or greater of rated capacity. Within 15 days after completing the survey, the project owner shall submit a summary report of the survey to the CPM. Included in the survey report shall be a description of any additional mitigation measures necessary to achieve compliance with the above listed noise limit, and a schedule, subject to CPM approval, for implementing these measures. When these measures are in place, the project owner shall repeat the noise survey.

NOISE-5 Following the project's first achieving a sustained output of 80% or greater of rated capacity, the project owner shall conduct an occupational noise survey to identify the noise hazardous areas in the facility.

The survey shall be conducted by a qualified person in accordance with the provisions of Title 8, California Code of Regulations sections 5095–5099 and Title 29, Code of Federal Regulations section 1910.95. The survey results shall be used to determine the magnitude of employee noise exposure.

The project owner shall prepare a report of the survey results and, if necessary, identify proposed mitigation measures that will be employed to comply with the applicable California and federal regulations.

Verification: Within 30 days after completing the survey, the project owner shall submit the noise survey report to the CPM. The project owner shall make the report available to OSHA and Cal/OSHA upon request.

STEAM BLOW RESTRICTIONS

NOISE-6 If a traditional, high-pressure steam blow process is employed, the project owner shall perform the steam blow in such a way that noise from steam blows is no greater than 110 dBA measured at a distance of 100 feet. The project owner shall conduct steam blows only during the hours of 8 a.m. to 5 p.m., unless the CPM agrees to longer hours based on a demonstration by the project owner that offsite noise impacts will not cause annoyance. If a low-pressure continuous steam blow process is employed, the project owner shall submit a description of this process, with expected noise levels and projected hours of execution, to the CPM.

Verification: At least 15 days prior to the first high-pressure steam blow, the project owner shall submit to the CPM a projection of the noise levels expected, and a description of the steam blow schedule. At least 15 days prior to any low-pressure continuous steam blow, the project owner shall submit to the CPM drawings or other information describing the process, including the noise levels expected and the projected time schedule for execution of the process.

NOISE-7 At least 15 days prior to the first steam blow(s), the project owner shall notify all residents or business owners within one-half mile of the site of the planned steam blow activity, and shall make the notification available to other area residents in an appropriate manner. The notification may be in the form of letters to the area residences, telephone calls, fliers or other effective means. The notification shall include a description of the purpose and nature of the steam blow(s), the proposed schedule, the expected sound levels, and the explanation that it is a one-time operation and not a part of normal plant operations.

Verification: Within five (5) days of notifying these entities, the project owner shall send a letter to the CPM confirming that they have been notified of the planned steam blow activities, including a description of the method(s) of that notification.

CONSTRUCTION TIME RESTRICTIONS

NOISE-8 Heavy equipment operation and noisy construction work relating to any project features shall be restricted to the times of day delineated below:

Weekdays	6:00 a.m. to 9:00 p.m.

Weekends	8:00 a.m. to 9:00 p.m.

Haul trucks and other engine-powered equipment shall be equipped with mufflers that meet all applicable regulations. Haul trucks shall be operated in accordance with posted speed limits. Truck engine exhaust brake use shall be limited to emergencies.

Verification: Prior to ground disturbance, the project owner shall transmit to the CPM a statement acknowledging that the above restrictions will be observed throughout the construction of the project.

EXHIBIT 1 - NOISE COMPLAINT RESOLUTION FORM

Hydrogen Energy California Project
(08-AFC-8)

NOISE COMPLAINT LOG NUMBER ______________________

Complainant's name and address:

Phone number: ______________________

Date complaint received: ______________________
Time complaint received: ______________________

Nature of noise complaint:

Definition of problem after investigation by plant personnel:

Date complainant first contacted: ______________________

Initial noise levels at 3 feet from noise source _________ dBA Date: ____________

Initial noise levels at complainant's property: __________ dBA Date: ____________

Final noise levels at 3 feet from noise source: ________ dBA Date: ____________

Final noise levels at complainant's property: __________ dBA Date: ____________

Description of corrective measures taken:

Complainant's signature: ______________________ Date: ____________

Approximate installed cost of corrective measures: $ ____________
Date installation completed: ____________
Date first letter sent to complainant: ____________ (copy attached)
Date final letter sent to complainant: ____________ (copy attached)

This information is certified to be correct:

Plant Manager's Signature: ______________________

(Attach additional pages and supporting documentation, as required).

REFERENCES

Kern County 2007 - Kern County General Plan, Noise Element. March 13, 2007.

Kern County 2009 - Kern County Code of Ordinance, Title 8, Chapter 8.36: Noise Control. Effective November 3, 2009.

HEI 2009c - Hydrogen Energy International, LLC /J. Briggs (tn 51735). Revised Application for Certification, dated 05/28/09. Submitted to CEC/Docket Unit on 05/28/09.

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NOISE APPENDIX A
FUNDAMENTAL CONCEPTS OF COMMUNITY NOISE

To describe noise environments and to assess impacts on noise sensitive area, a frequency weighting measure, which simulates human perception, is customarily used. It has been found that “A-weighting” of sound intensities best reflects the human ear’s reduced sensitivity to low frequencies and correlates well with human perceptions of the annoying aspects of noise. The A-weighted decibel scale (dBA) is cited in most noise criteria. Decibels are logarithmic units that conveniently compare the wide range of sound intensities to which the human ear is sensitive. **NOISE Table A1** provides a description of technical terms related to noise.

Noise environments and consequences of human activities are usually well represented by an equivalent A-weighted sound level over a given time period (L_{eq}), or by average day and night A-weighted sound levels with a nighttime weighting of 10 dBA (L_{dn}). Noise levels are generally considered low when ambient levels are below 45 dBA, moderate in the 45 to 60 dBA range, and high above 60 dBA. Outdoor day-night sound levels vary over 50 dBA depending on the specific type of land use. Typical L_{dn} values might be 35 dBA for a wilderness area, 50 dBA for a small town or wooded residential area, 65 to 75 dBA for a major metropolis downtown (e.g., San Francisco), and 80 to 85 dBA near a freeway or airport. Although people often accept the higher levels associated with very noisy urban residential and residential-commercial zones, those higher levels nevertheless are considered to be levels of noise adverse to public health.

Various environments can be characterized by noise levels that are generally considered acceptable or unacceptable. Lower levels are expected in rural or suburban areas than would be expected for commercial or industrial zones. Nighttime ambient levels in urban environments are about seven decibels lower than the corresponding average daytime levels. The day-to-night difference in rural areas away from roads and other human activity can be considerably less. Areas with full-time human occupation that are subject to nighttime noise, which does not decrease relative to daytime levels, are often considered objectionable. Noise levels above 45 dBA at night can result in the onset of sleep interference effects. At 70 dBA, sleep interference effects become considerable (U.S. Environmental Protection Agency, Effects of Noise on People, December 31, 1971).

To help the reader understand the concept of noise in decibels (dBA), **NOISE Table A2** illustrates common noises and their associated sound levels, in dBA.

NOISE Table A1
Definition of Some Technical Terms Related to Noise

Terms	Definitions
Decibel, dB	A unit describing the amplitude of sound, equal to 20 times the logarithm to the base 10 of the ratio of the pressure of the sound measured to the reference pressure, which is 20 micropascals (20 micronewtons per square meter).
Frequency, Hz	The number of complete pressure fluctuations per second above and below atmospheric pressure.
A-Weighted Sound Level, dBA	The sound pressure level in decibels as measured on a sound level meter using the A-weighting filter network. The A-weighting filter de-emphasizes the very low and very high frequency components of the sound in a manner similar to the frequency response of the human ear and correlates well with subjective reactions to noise. All sound levels in this testimony are A-weighted.
L_{10}, L_{50}, & L_{90}	The A-weighted noise levels that are exceeded 10%, 50%, and 90% of the time, respectively, during the measurement period. L_{90} is generally taken as the background noise level.
Equivalent Noise Level, L_{eq}	The energy average A-weighted noise level during the noise level measurement period.
Community Noise Equivalent Level, CNEL	The average A-weighted noise level during a 24-hour day, obtained after addition of 4.8 decibels to levels in the evening from 7 p.m. to 10 p.m., and after addition of 10 decibels to sound levels in the night between 10 p.m. and 7 a.m.
Day-Night Level, L_{dn} or DNL	The Average A-weighted noise level during a 24-hour day, obtained after addition of 10 decibels to levels measured in the night between 10 p.m. and 7 a.m.
Ambient Noise Level	The composite of noise from all sources, near and far. The normal or existing level of environmental noise at a given location.
Intrusive Noise	That noise that intrudes over and above the existing ambient noise at a given location. The relative intrusiveness of a sound depends upon its amplitude, duration, frequency, and time of occurrence and tonal or informational content as well as the prevailing ambient noise level.
Pure Tone	A pure tone is defined by the Model Community Noise Control Ordinance as existing if the one-third octave band sound pressure level in the band with the tone exceeds the arithmetic average of the two contiguous bands by 5 decibels (dB) for center frequencies of 500 Hz and above, or by 8 dB for center frequencies between 160 Hz and 400 Hz, or by 15 dB for center frequencies less than or equal to 125 Hz.

Source: Guidelines for the Preparation and Content of Noise Elements of the General Plan, Model Community Noise Control Ordinance, California Department of Health Services 1976, 1977.

NOISE Table A2
Typical Environmental and Industry Sound Levels

Noise Source (at distance)	A-Weighted Sound Level in Decibels (dBA)	Noise Environment	Subjective Impression
Civil Defense Siren (100')	140-130		Pain Threshold
Jet Takeoff (200')	120		Very Loud
Very Loud Music	110	Rock Music Concert	
Pile Driver (50')	100		
Ambulance Siren (100')	90	Boiler Room	
Freight Cars (50')	85		
Pneumatic Drill (50')	80	Printing Press Kitchen with Garbage Disposal Running	Loud
Freeway (100')	70		Moderately Loud
Vacuum Cleaner (100')	60	Data Processing Center Department Store/Office	
Light Traffic (100')	50	Private Business Office	
Large Transformer (200')	40		Quiet
Soft Whisper (5')	30	Quiet Bedroom	
	20	Recording Studio	
	10		Threshold of Hearing

Source: Handbook of Noise Measurement, Arnold P.G. Peterson, 1980

Subjective Response to Noise

The adverse effects of noise on people can be classified into three general categories:

- Subjective effects of annoyance, nuisance, dissatisfaction.
- Interference with activities such as speech, sleep, and learning.
- Physiological effects such as anxiety or hearing loss.

The sound levels associated with environmental noise, in almost every case, produce effects only in the first two categories. Workers in industrial plants can experience noise effects in the last category. There is no completely satisfactory way to measure the subjective effects of noise or of the corresponding reactions of annoyance and dissatisfaction, primarily because of the wide variation in individual tolerance of noise.

One way to determine a person's subjective reaction to a new noise is to compare the level of the existing (background) noise, to which one has become accustomed, with the level of the new noise. In general, the more the level or the tonal variations of a new noise exceed the previously existing ambient noise level or tonal quality, the less acceptable the new noise will be, as judged by the exposed individual.

With regard to increases in A-weighted noise levels, knowledge of the following relationships can be helpful in understanding the significance of human exposure to noise.

1. Except under special conditions, a change in sound level of 1 dB cannot be perceived.

2. Outside of the laboratory, a 3-dB change is considered a barely noticeable difference.

3. A change in level of at least 5 dB is required before any noticeable change in community response would be expected.

4. A 10-dB change is subjectively heard as an approximate doubling in loudness and almost always causes an adverse community response (Kryter, Karl D., The Effects of Noise on Man, 1970).

Combination of Sound Levels

People perceive both the level and frequency of sound in a non-linear way. A doubling of sound energy (for instance, from two identical automobiles passing simultaneously) creates a 3-dB increase (i.e., the resultant sound level is the sound level from a single passing automobile plus 3 dB). **NOISE Table A3** indicates the rules for decibel addition used in community noise prediction.

NOISE Table A3
Addition of Decibel Values

When two decibel values differ by:	Add the following amount to the larger value
0 to 1 dB	3 dB
2 to 3 dB	2 dB
4 to 9 dB	1 dB
10 dB or more	0
Figures in this table are accurate to ± 1 dB.	

Source: Architectural Acoustics, M. David Egan, 1988.

Sound and Distance

Doubling the distance from a noise source reduces the sound pressure level by 6 dB.

Increasing the distance from a noise source 10 times reduces the sound pressure level by 20 dB.

Worker Protection

OSHA noise regulations are designed to protect workers against the effects of noise exposure and list permissible noise level exposure as a function of the amount of time to which the worker is exposed, as shown in **NOISE Table A4**.

NOISE Table A4
OSHA Worker Noise Exposure Standards

Duration of Noise (Hrs/day)	A-Weighted Noise Level (dBA)
8.0	90
6.0	92
4.0	95
3.0	97
2.0	100
1.5	102
1.0	105
0.5	110
0.25	115

Source: 29 CFR § 1910.95.

PUBLIC HEALTH

Alvin Greenberg, Ph.D.

SUMMARY OF CONCLUSIONS

Staff has analyzed potential public health risks associated with construction and operation of the Hydrogen Energy California (HECA) project and does not expect any significant adverse cancer or short- or long-term noncancer health effects from project toxic emissions. Staff's analysis of potential health impacts from the proposed HECA project was based on a conservative health protective methodology that accounts for impacts to the most sensitive individuals in a given population, including newborns and infants. According to the results of staff's health risk assessment, emissions from the HECA would not contribute significantly to morbidity or mortality in any age or ethnic group residing in the project area.

Staff notes that the proposed HECA project is a complex industrial facility similar in scope to a small refinery. The presence of numerous chemical processes -- specifically the larger gasification process and sulfur recovery process that will require the use of large amounts of hazardous materials in closed tanks and piping at elevated temperature and pressure -- pose significant risks of fugitive emissions and accidental releases of toxic air contaminants if not managed properly. Staff has not encountered such a complex power generation facility in the history of the Energy Commission. In order to properly review the expected and unexpected emissions from this project, staff spent considerable time evaluating the entire process and even visited a similar gasification facility in Polk County, Florida. As a result of staff's efforts to understand the process and the risks involved, staff determined that in order to keep source, fugitive, and accidental emissions to a level that would not present a significant risk to public health, several processes must be managed in greater detail than usual, even if the quantities of hazardous materials present are below the federal or state thresholds that would trigger this increased level of management. Please refer to the analysis in the **Hazardous Materials Management** section of this PSA for further details.

INTRODUCTION

The purpose of this Preliminary Staff Assessment (PSA) is to determine if emissions of toxic air contaminants (TACs) from the proposed HECA would have the potential to cause significant adverse public health impacts or to violate standards for public health protection. If potentially significant health impacts are identified, staff will evaluate mitigation measures to reduce such impacts to insignificant levels.

California Energy Commission (Energy Commission) staff addresses potential impacts of regulated or criteria air pollutants in the **Air Quality** section of this PSA, and impacts on public and worker health from accidental releases of hazardous materials are examined in the **Hazardous Materials Management** section. Health effects from electromagnetic fields are discussed in the **Transmission Line Safety and Nuisance** section. Pollutants released from the project in wastewater streams to the public sewer system are discussed in the **Soil and Water Resources** section. Plant releases in the form of hazardous and nonhazardous wastes are described in the **Waste Management** section.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

PUBLIC HEALTH Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
Clean Air Act section 112 (Title 42, U.S. Code section 7412)	This act requires new sources that emit more than 10 tons per year of any specified Hazardous Air Pollutant (HAP) or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology.
40 CFR 63 Subpart DDDDD	This rule applies maximum achievable control technology (MACT) standards for boilers at a major source of hazardous air pollutants to biomass combustors.
State	
California Health and Safety Code section 25249.5 et seq. (Proposition 65)	These sections establish thresholds of exposure to carcinogenic substances above which Prop 65 exposure warnings are required.
California Health and Safety Code section 41700	This section states that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which 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."
California Public Resource Code section 25523(a); Title 20 California Code of Regulations (CCR) section 1752.5, 2300–2309 and Division 2 Chapter 5, Article 1, Appendix B, Part (1); California Clean Air Act, Health and Safety Code section 39650, et seq.	These regulations require a quantitative health risk assessment for new or modified sources, including power plants that emit one or more toxic air contaminants (TACs).
California Health and Safety Code, Sections 44360 to 44366 (Air Toxic Hot Spots Information and Assessment Act)	Establishes acceptable levels for toxic contaminants based on the results of a health risk analysis (HRA).
Local	
San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 2520, Section 2.1	This rule requires Federally Mandated Operating Permits for major sources of air toxics.
SJVAPCD Rule 2550	This rule requires the use of Technologically-Best Available Control Technolgy (T-BACT) for major sources of hazardous air pollutants in order to achieve MACT.
SJVAPCD Rule 4102, Section 4.1 and Policy APR 1905	This rule requires the preparation of an HRA and prohibits sources from discharging air toxics that are detrimental to public health.

SETTING

This section describes the environment in the vicinity of the proposed project site from the public health perspective. Characteristics of the natural environment, such as meteorology and terrain, affect the project's potential for causing impacts on public health. An emissions plume from a facility may affect elevated areas before lower terrain areas due to a reduced opportunity for atmospheric mixing. Also, the types of land use near a site influence the surrounding population distribution and density, which, in turn, affect public exposure to project emissions. Additional factors affecting potential public health impacts include existing air quality, existing public health concerns, and environmental site contamination.

SITE AND VICINITY DESCRIPTION

The project site is located in a rural area that is sparsely populated and primarily dedicated to agricultural uses. Land in the general vicinity of the proposed project is designated for agricultural uses as well as some commercial and residential uses. Sensitive receptors in the project vicinity are shown in Figure 5.6-1 of the AFC. The nearest sensitive receptor is the Tule Elk State Natural Reserve, located about 1,700 feet east of the project site. The only other sensitive receptor within a 6-mile radius of the project site is the Elk Hills Elementary School, located approximately 1.3 miles southeast of the site boundary. The nearest residences are located approximately 370 feet northwest of the project site and several hundred feet east of the project site (at the intersection of Tupman Rd and Station Rd). Additional residences are located approximately 1,400 feet to the east and 3,300 feet to the southeast of the project site. The unincorporated community of Tupman is about 1.5 miles southeast of the project site. (HEI 2008c, Sections 5.6 & 5.6.1).

The location of elevated terrain (above the stack height) is important in assessing potential exposure, as an emission plume may impact high elevations before impacting lower elevations. The topography of the site and the surrounding area is essentially flat, ranging from about 282 feet to 291 feet above sea level. The heat recovery steam generator (HRSG) exhaust stack height would be 213 feet and the auxiliary combustion turbine generator (CTG) stack height would be 110 feet (HEI 2008c, Section 5.1.2.3). Terrain above stack height begins approximately 2 miles south and southwest of the project site where hills begin to rise (HEI 2008c, Section 5.6 and Figure 2-7).

METEOROLOGY

Meteorological conditions, including wind speed, wind direction, and atmospheric stability, affect the extent to which pollutants are dispersed into ambient air as well as the direction of pollutant transport. This, in turn, affects the level of public exposure to emitted pollutants and associated health risks. When wind speeds are low and the atmosphere is stable, for example, dispersion is reduced, and localized exposure may be increased.

The project region is characterized by a Mediterranean climate; summers are warm and dry and winters are cool with mild precipitation. The average annual rainfall is six inches and 80% of it occurs between November and March. Winds flow predominantly from the northwest and north, but some variations occur during fall and winter (HEI 2008c, Section 5.1.1.1).

Atmospheric stability is a measure related to turbulence, or the ability of the atmosphere to disperse pollutants due to convective air movement. Mixing heights (the height above ground level through which the air is well mixed and in which pollutants can be dispersed) are lower during mornings due to temperature inversions and increase during the warmer afternoons. Staff's **Air Quality** section presents more detailed meteorological data.

EXISTING AIR QUALITY

The proposed site is within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SJVAPCD). By examining average toxic concentration levels from representative air monitoring sites with cancer risk factors specific to each contaminant, lifetime cancer risk can be calculated to provide a background risk level for inhalation of ambient air. For comparison purposes, it should be noted that the overall lifetime cancer risk for the average individual in the United States is about 1 in 3, or 333,000 in 1 million.

The nearest monitoring station that measures PM10 and PM 2,5 is the Bakersfield Golden Highway station located about 21 miles east of the project site. The annual arithmetic mean for PM10 measured at this monitoring station ranged between 43.2 and 55.4 $\mu g/m^3$ during the years 2005 to 2007. The annual arithmetic mean for PM2.5 ranged between 18.6 and 25.5 during the same period (HEI 2008c, Section 5.1.1.2 and Tables 5.1-4 - 5.1-5).

The nearest California Air Resources Board (CARB) air toxics monitoring station that actively reports values is located on California Avenue in Bakersfield, approximately 20 miles east of the project site. In 2008, the background cancer risk calculated by CARB for the Bakersfield California Ave monitoring station was 92 in one million (CARB 2009). The pollutants 1,3-butadiene and benzene, emitted primarily from mobile sources, accounted together for more than half of the total risk. The risk from 1,3-butadiene was about 25 in one million, while the risk from benzene was about 33 in one million. Formaldehyde accounts for about 21% of the 2008 average calculated cancer risk based on air toxics monitoring results, with a risk of about 19 in one million. Formaldehyde is emitted directly from vehicles and other combustion sources, such as the proposed facility. The risk from hexavalent chromium was about 5 in one million, or ~5% of the total risk.

The use of reformulated gasoline, beginning in the second quarter of 1996, as well as other toxics reduction measures, have led to a decrease of ambient levels of toxics and associated cancer risk during the past few years in all areas of the state and the nation. For example, in the San Francisco Bay Area, cancer risk was 342 in 1 million based on 1992 data, 315 in 1 million based on 1994 data, and 303 in 1 million based on 1995 data. In 2002, the most recent year for which data is available, the average inhalation cancer risk decreased to 162 in 1 million (BAAQMD 2004b, p. 12).

EXISTING PUBLIC HEALTH CONCERNS

When evaluating a new project, staff sometimes conducts a detailed study and analysis of existing public health issues in the project vicinity. This analysis is prepared in order to identify the current status of respiratory diseases (including asthma), cancer, and childhood mortality rates in the population located near the proposed project. Assessing existing health concerns in the project area will provide staff with a basis on which to evaluate the significance of any additional health impacts from the proposed HECA project and evaluate any proposed mitigation. In this case, however, no existing health issues have been reported within a 6-mile radius of the project (HEI 2008c, Section 5.6.1) and therefore a detailed analysis was not conducted. The average cancer mortality rate in Kern County is 183 per 100,000 people, which is just slightly below the state average. Mortality rates from Coronary Heart Disease in Kern County however are many times higher than the state average with 1,320.7 deaths per 100,000 people compared to 163.1 deaths per 100,000 people (HEI 2008c, Section 5.6.1).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

The **PUBLIC HEALTH** section of this staff assessment discusses toxic emissions to which the public could be exposed during project construction and routine operation. Following the release of toxic contaminants into the air or water, people may come into contact with them through inhalation, dermal contact, or ingestion via contaminated food or water.

Air pollutants for which no ambient air quality standards have been established are called noncriteria pollutants. Unlike criteria pollutants such as ozone, carbon monoxide, sulfur dioxide, or nitrogen dioxide, noncriteria pollutants have no ambient (outdoor) air quality standards that specify levels considered safe for everyone.

Since noncriteria pollutants do not have such standards, a health risk assessment is used to determine if people might be exposed to those types of pollutants at unhealthy levels. The risk assessment consists of the following steps:

- identify the types and amounts of hazardous substances that HECA could emit to the environment;
- estimate worst-case concentrations of project emissions in the environment using dispersion modeling;
- estimate amounts of pollutants that people could be exposed to through inhalation, ingestion, and dermal contact; and
- characterize potential health risks by comparing worst-case exposure to safe standards based on known health effects.

Staff relies upon the expertise of the California Environmental Protection Agency (Cal/EPA) Office of Environmental Health Hazard Assessment (OEHHA) to identify contaminants that are known to the state to cause cancer or other noncancer toxicological endpoints and to calculate the toxicity and cancer potency factors of these contaminants. Staff also relies upon the expertise of the California Air Resources Board and the local air districts to conduct ambient air monitoring of toxic air contaminants and the state Department of Public Health to conduct epidemiological investigations into the impacts of pollutants on communities. It is not within the purview or the expertise of the Energy Commission staff to duplicate the expertise and statutory responsibility of these agencies.

Initially, a screening level risk assessment is performed using simplified assumptions that are intentionally biased toward protection of public health. That is, an analysis is designed that overestimates public health impacts from exposure to project emissions. In reality, it is likely that the actual risks from the power plant will be much lower than the risks as estimated by the screening level assessment. The risks for screening purposes are based on examining conditions that would lead to the highest, or worst-case, risks and then using those conditions in the study. Such conditions include:

- using the highest levels of pollutants that could be emitted from the plant;
- assuming weather conditions that would lead to the maximum ambient concentration of pollutants;
- using the type of air quality computer model which predicts the greatest plausible impacts;
- calculating health risks at the location where the pollutant concentrations are estimated to be the highest;
- assuming that an individual's exposure to cancer-causing agents occurs continuously for 70 years; and
- using health-based standards designed to protect the most sensitive members of the population (i.e., the young, elderly, and those with respiratory illnesses).

A screening level risk assessment will, at a minimum, include the potential health effects from inhaling hazardous substances. Some facilities may also emit certain substances that could present a health hazard from noninhalation pathways of exposure (OEHHA 2003, Tables 5.1, 6.3, 7.1). When these substances are present in facility emissions, the screening level analysis includes the following additional exposure pathways: soil ingestion, dermal exposure, and mother's milk (OEHHA 2003, p. 5-3).

The risk assessment process addresses three categories of health impacts: acute (short-term) health effects, chronic (long-term) noncancer effects, and cancer risk (also long-term). Acute health effects result from short-term (one-hour) exposure to relatively high concentrations of pollutants. Acute effects are temporary in nature and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic health effects are those that arise as a result of long-term exposure to lower concentrations of pollutants. The exposure period is considered to be approximately from 12% to 100% of a lifetime, or from 8 to 70 years (OEHHA 2003, p. 6-5). Chronic health effects include diseases such as reduced lung function and heart disease.

The analysis for noncancer health effects compares the maximum project contaminant levels to safe levels called *Reference Exposure Levels*, or RELs. These are amounts of toxic substances to which even sensitive people can be exposed and suffer no adverse health effects (OEHHA 2003, p. 6-2). These exposure levels are designed to protect the most sensitive individuals in the population, such as infants, the aged, and people suffering from illness or disease which makes them more sensitive to the effects of toxic substance exposure. The Reference Exposure Levels are based on the most sensitive adverse health effect reported in the medical and toxicological literature and include margins of safety. The margin of safety addresses uncertainties associated with inconclusive scientific and technical information available at the time of standard setting and is meant to provide a reasonable degree of protection against hazards that research has not yet identified. The margin of safety is designed to prevent pollution levels that have been demonstrated to be harmful, as well as to prevent lower pollutant levels that may pose an unacceptable risk of harm, even if the risk is not precisely identified as to nature or degree. Health protection is achieved if the estimated worst-case exposure is below the relevant reference exposure level. In such a case, an adequate margin of safety exists between the predicted exposure and the estimated threshold dose for toxicity.

Exposure to multiple toxic substances may result in health effects that are equal to, less than, or greater than effects resulting from exposure to the individual chemicals. Only a small fraction of the thousands of potential combinations of chemicals have been tested for the health effects of combined exposures. In conformity with the California Air Pollution Control Officers Association (CAPCOA) guidelines, the health risk assessment assumes that the effects of each substance are additive for a given organ system (OEHHA 2003, pp. 1-5, 8-12). Other possible mechanisms due to multiple exposures include those cases where the actions may be synergistic or antagonistic (where the effects are greater or less than the sum, respectively). For these types of substances, the health risk assessment could underestimate or overestimate the risks.

For carcinogenic substances, the health assessment considers the risk of developing cancer and assumes that continuous exposure to the cancer-causing substance occurs over a 70-year lifetime. The risk that is calculated is not meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound number based on worst-case assumptions.

Cancer risk is expressed in chances per million and is a function of the maximum expected pollutant concentration, the probability that a particular pollutant will cause cancer (called *potency factors* and established by OEHHA), and the length of the exposure period. Cancer risks for each carcinogen are added to yield total cancer risk. The conservative nature of the screening assumptions used means that actual cancer risks due to project emissions are likely to be considerably lower than those estimated.

The screening analysis is performed to assess worst-case risks to public health associated with the proposed project. If the screening analysis predicts no significant risks, then no further analysis is required. However, if risks are above the significance level, then further analysis, using more realistic site-specific assumptions, would be performed to obtain a more accurate assessment of potential public health risks.

Significance Criteria

Energy Commission staff determines the health effects of exposure to toxic emissions based on impacts to the maximum exposed individual. This is a person hypothetically exposed to project emissions at a location where the highest ambient impacts were calculated using worst-case assumptions, as described above.

As described earlier, noncriteria pollutants are evaluated for short-term (acute) and long-term (chronic) noncancer health effects, as well as cancer (long-term) health effects. The significance of project health impacts is determined separately for each of the three categories.

Acute and Chronic Noncancer Health Effects

Staff assesses the significance of noncancer health effects by calculating a *hazard index*. A hazard index is a ratio comparing exposure from facility emissions to the reference (safe) exposure level. A ratio of less than 1.0 signifies that the worst-case exposure is below the safe level. The hazard index for every toxic substance that has the same type of health effect is added to yield a Total Hazard Index. The Total Hazard Index is calculated separately for acute and chronic effects. A Total Hazard Index of less than 1.0 indicates that cumulative worst-case exposures are less than the reference exposure levels. Under these conditions, health protection from the project is likely to be achieved, even for sensitive members of the population. In such a case, staff presumes that there would be no significant noncancer project-related public health impacts.

Cancer Risk

Staff relied upon regulations implementing the provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986, (Health & Safety Code, §§25249.5 et seq.) for guidance to determine a cancer risk significance level. Title 22, California Code of Regulations section 12703(b) states that “the risk level which represents no significant risk shall be one which is calculated to result in one excess case of cancer in an exposed population of 100,000, assuming lifetime exposure.” This level of risk is equivalent to a cancer risk of 10 in 1 million, which is also written as 10×10^{-6}. An important distinction is that the Proposition 65 significance level applies separately to each cancer-causing substance, whereas staff determines significance based on the total risk from all cancer-causing chemicals. Thus, the manner in which the significance level is applied by staff is more conservative (health-protective) than that applied by Proposition 65. The significant risk level of 10 in 1 million is consistent with the level of significance adopted by many air districts. In general, these air districts would not approve a project with a cancer risk exceeding 10 in 1 million. The SJVAPCD also uses 10 in 1 million as the level of “Significant Health Risk” (SJVAPCD 2006).

As noted earlier, the initial risk analysis for a project is typically performed at a screening level, which is designed to overstate actual risks, so that health protection can be ensured. Staff’s analysis also addresses potential impacts on all members of the population including the young, the elderly, people with existing medical conditions that may make them more sensitive to the adverse effects of toxic air contaminants, and any minority or low-income populations that are likely to be disproportionately affected by impacts. To accomplish this goal, staff uses the most current acceptable public health exposure levels (both acute and chronic) set to protect the public from the effects of airborne toxics. When a screening analysis shows cancer risks to be above the significance level, refined assumptions would likely result in a lower, more realistic risk estimate. Based on refined assumptions, if risk posed by the facility exceeds the significance level of 10 in 1 million, staff would require appropriate measures to reduce the risk to less than significant. If, after all risk reduction measures had been considered, a refined analysis identifies a cancer risk greater than 10 in 1 million, staff would deem such risk to be significant and would not recommend project approval.

DIRECT/INDIRECT IMPACTS AND MITIGATION

CONSTRUCTION IMPACTS AND MITIGATION

Potential risks to public health during construction may be associated with exposure to toxic substances in contaminated soil disturbed during site preparation, as well as diesel exhaust from heavy equipment operation. Criteria pollutant impacts from the operation of heavy equipment and particulate matter from earth moving are examined in staff's **Air Quality** analysis.

Site disturbances occur during facility construction from excavation, grading, and earth moving. Such activities have the potential to adversely affect public health through various mechanisms, such as the creation of airborne dust, material being carried off site through soil erosion, and uncovering buried hazardous substances. The Phase I Environmental Site Assessment conducted for this site in 2009 found several environmental conditions that may have potentially impacted the soil at the project site. Most of the potential contamination at the site is due to underground storage tanks and the historical use of the site for fertilizer manufacturing. The Phase I ESA recommended further investigations to characterize contamination at the site (HEI 2008c, Appendix M).

In the event that any contamination is encountered during construction, proposed Conditions of Certification **Waste-1** and **Waste-2** (which require a registered professional engineer or geologist to be available during soil excavation and grading to ensure proper handling and disposal of contaminated soil) would ensure that contaminated soil does not affect the public. See the staff assessment section on **Waste Management** for a more detailed analysis of this topic.

The operation of construction equipment will result in air emissions from diesel-fueled engines. Diesel emissions are generated from sources such as trucks, graders, cranes, welding machines, electric generators, air compressors, and water pumps. Although diesel exhaust contains criteria pollutants such as nitrogen oxides, carbon monoxide, and sulfur oxides, it also includes a complex mixture of thousands of gases and fine particles. These particles are primarily composed of aggregates of spherical carbon particles coated with organic and inorganic substances. Diesel exhaust contains over 40 substances that are listed by the U.S. Environmental Protection Agency (U.S. EPA) as hazardous air pollutants and by the California Air Resources Board (ARB) as toxic air contaminants.

Exposure to diesel exhaust may cause both short- and long-term adverse health effects. Short-term effects can include increased coughing, labored breathing, chest tightness, wheezing, and eye and nasal irritation. Long-term effects can include increased coughing, chronic bronchitis, reductions in lung function, and inflammation of the lung. Epidemiological studies also strongly suggest a causal relationship between occupational diesel exhaust exposure and lung cancer.

Based on a number of health effects studies, the Scientific Review Panel on Toxic Air Contaminants recommended a chronic reference exposure level (see discussion of reference exposure levels in Method of Analysis section above) for diesel exhaust particulate matter of 5 micrograms of diesel particulate matter per cubic meter of air ($\mu g/m^3$) and a cancer unit risk factor of $3x10^{-4}$ $(\mu g/m^3)^{-1}$ (SRP 1998, p. 6). The Scientific Review Panel did not recommend a value for an acute Reference Exposure Level since available data in support of a value was deemed insufficient. On August 27, 1998, ARB listed particulate emissions from diesel-fueled engines as a toxic air contaminant and approved the panel's recommendations regarding health effect levels.

Construction of the HECA project is anticipated to take place over a period of 44 months. Appendix D of the Revised AFC and Attachment 85-1 of Data Responses Set 1 present monthly and annual maximum construction emissions from construction equipment diesel exhaust. In response to Data Request 85, the applicant conducted a health risk assessment for diesel particulate matter from construction activities. The applicant used the annual emissions associated with the peak construction period to estimate PM10 concentrations and adjusted the exposure period to reflect the 4-year duration. As noted earlier, assessment of chronic (long-term) health effects assumes continuous exposure to toxic substances over a significantly longer time period, typically from 8 to 70 years. The applicant's HRA calculations resulted in a cancer risk of 7.0 in 1,000,000 and a chronic hazard index of 0.06 at the point of maximum impact, both below the level of significance. Health risks calculated at the locations of the nearest worker, nearest residence, and nearest sensitive receptor were all significantly lower (URS 2010c, Table 85-1).

Mitigation measures are proposed by both the applicant and Energy Commission staff to reduce the maximum calculated PM10 emissions. These include the use of extensive fugitive dust control measures. The fugitive dust control measures are assumed to result in 90% reductions of emissions. In order to further mitigate potential impacts from particulate emissions during the operation of diesel-powered construction equipment, the use of ultra-low sulfur diesel fuel and Tier 2 or Tier 1 California Emission Standards for Off-Road Compression-Ignition Engines and the installation of an oxidation catalyst and soot filters on diesel equipment are required. The catalyzed diesel particulate filters are passive, self-regenerating filters that reduce particulate matter, carbon monoxide, and hydrocarbon emissions through catalytic oxidation and filtration. The degree of particulate matter reduction is comparable for both mitigation measures in the range of approximately 85–92%. Such filters will reduce diesel emissions during construction and reduce any potential for significant health impacts.

Valley Fever

Coccidioidomycosis or "Valley Fever" (VF) is a disease caused by inhaling spores of the fungus Coccidioides immitis, which is present in the soil of the San Joaquin Valley and other regions of Southern California and Arizona. Kern County, located at the southern end of San Joaquin valley, is where valley fever occurs most frequently. The disease usually affects the lungs and can have potentially severe consequences, especially in at-risk individuals such as the elderly, pregnant women, and people with compromised immune systems. Staff has addressed this issue in-depth in the **Worker Safety/Fire Protection** section of this PSA. Staff believes that the persons who would have the greatest exposure and thus who would be most at risk are the workers involved in soil disturbance activities or those on the site when soil is moved during grading and excavation. Staff contends that if the workers are protected to the greatest extent possible from contracting Valley Fever, then the off-site public would also be protected.

OPERATION IMPACTS AND MITIGATION

Emissions Sources

The emissions sources at the proposed HECA are many and include the heat recovery steam generator (HRSG) combustion turbine, power block cooling towers, gasifier refractory heaters, auxiliary boiler, gasification flare, SRU flare, rectisol flare, tail gas thermal oxidizer, carbon dioxide vent, diesel emergency generator, a diesel fire pump engine, heavy truck traffic associated with petcoke, coal, and gasifier solids handling, and fugitive emissions from various plant components (URS 2010c, Date Response 89). As noted earlier, the first step in a health risk assessment is to identify potentially toxic compounds that may be emitted from the facility.

Tables 5.6-2 through 5.6-14 and Table 89-1 of the applicant's Response to Data Requests Set 1 (URS 2010c) list noncriteria pollutants that may be emitted from all sources at the HECA, along with their anticipated amounts (emission factors). Toxic Air Contaminant emission factors were obtained from the Environmental Protection Agency (EPA) AP-42 database of emission factors and from other sources as noted in the respective table for each project component. Table 89-1 provides estimates of fugitive emissions from various plant components such as methanol, propylene, acid gas, and ammonia-laden gas from pumps, valves, and connectors. The applicant will implement an Leak Detection and Repair (LDAR) program to identify and repair leaking equipment and thereby reduce fugitive emissions. The applicants HRA included total TAC emissions estimated for all sources listed above (including fugitive emissions) as listed in Table 89-4 (URS 2010c, Data Response 89).

Staff also requested that the applicant identify and quantify any radioisotopes potentially released from pet coke and coal during gasification. The applicant responded that based on information provided in a National Institute of Occupational Safety and Health (NIOSH) document, coal is typically radioactive to the same extent as sedimentary rock. That is, coal is expected to have only trace amounts of radioisotopes and no significant radiological exposure is expected from coal gasification (URS 2010b, Data Response 150).

Table 5.16-1 of the AFC lists toxicity values used to characterize cancer and noncancer health impacts from project pollutants. The toxicity values include Reference Exposure Levels, which are used to calculate short-term and long-term noncancer health effects, and cancer unit risks, which are used to calculate the lifetime risk of developing cancer, as published in the OEHHA Guidelines (OEHHA 2003). **PUBLIC HEALTH Table 3** lists the toxic emissions potentially emitted by the HECA and shows how each contributes to the health risk analysis.

PUBLIC HEALTH Table 3: Health Impacts and Exposure Routes Attributed to Toxic Emissions from the proposed facility

Substance	Oral Cancer	Oral Noncancer	Inhalation Cancer	Noncancer (Chronic)	Noncancer (Acute)
1,3-Butadiene			✔	✔	
Acetaldehyde			✔	✔	
Acrolein				✔	✔
Ammonia				✔	✔
Arsenic	✔	✔	✔	✔	✔
Benzene			✔	✔	✔
Beryllium			✔	✔	
Cadmium		✔	✔	✔	
Carbon Disulfide				✔	✔
Chromium, Total			✔	✔	
Copper					✔
Cyanides				✔	✔
Dichlorobenzene				✔	
Diesel Particulate			✔	✔	
Ethylbenzene			✔	✔	
Fluoride				✔	✔
Formaldehyde			✔	✔	✔
Hexane				✔	
HCl				✔	✔
Hydrogen Fluoride				✔	✔
Hydrogen Sulfide				✔	✔
Lead	✔		✔		
Manganese				✔	
Mercury		✔		✔	✔
Methyl Bromide				✔	✔
Methylene Chloride			✔	✔	✔
Naphthalene			✔	✔	
n-Hexane				✔	
Nickel		✔	✔	✔	✔
Phenol				✔	✔
PAHs	✔	✔	✔		
Propylene				✔	
Propylene Oxide			✔	✔	✔

Selenium				✔	✔
Sulfuric Acid and Sulfate				✔	✔
Toluene				✔	✔
Vanadium					✔
Xylene				✔	✔

Source: OEHHA 2003, Appendix L and HEI 2008c, Table 5.16-1.

Emissions Levels

Once potential emissions are identified, the next step is to quantify them by conducting a “worst case” analysis. Maximum hourly emissions are required to calculate acute (one-hour) noncancer health effects, while estimates of maximum emissions on an annual basis are required to calculate cancer and chronic (long-term) noncancer health effects.

The next step in the health risk assessment process is to estimate the ambient concentrations of toxic substances. This is accomplished by using a screening air dispersion model and assuming conditions that result in maximum impacts. The applicant’s screening analysis was performed using the ARB/OEHHA Hotspots Analysis and Reporting Program (HARP). Ambient concentrations were used in conjunction with Reference Exposure Levels and cancer unit risk factors to estimate health effects that might occur from exposure to facility emissions. Exposure pathways, or ways in which people might come into contact with toxic substances, include inhalation, dermal (through the skin) absorption, soil ingestion, consumption of locally grown plant foods, and mother’s milk.

The above method of assessing health effects is consistent with OEHHA’s Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA, 2003) referred to earlier and results in the following health risk estimates.
Impacts

The applicant’s screening health risk assessment for the project including emissions from all sources as presented in Data Response 86 (URS 2010c) resulted in a maximum acute Hazard Index (HI) of 0.79 and a maximum chronic HI of 0.27 at the point of maximum impact (PMI). The total worst-case individual cancer risk was calculated by the applicant to be 3.02 in 1 million at the PMI. Calculated health risks at the location of the maximum exposed worker, maximum exposed residence, and nearest sensitive receptor were all significantly lower (URS 2010c, Table 86-1). As **PUBLIC HEALTH Table 4** shows, both acute and chronic hazard indices are less than 1.0, and cancer risk is less than 10 in 1 million, indicating that no short- or long-term adverse health effects are expected.

PUBLIC HEALTH Table 4
Operation Hazard/Risk at Point of Maximum Impact: Applicant Assessment

Type of Hazard/Risk	Hazard Index/Risk	Significance Level	Significant?
Acute Noncancer	0.79	1.0	No
Chronic Noncancer	0.27	1.0	No
Individual Cancer	3.02 in a million	10.0 in a million	No

Source URS 2010c, Table 86-1

Staff conducted a quantitative evaluation of the risk assessment results presented in the Hydrogen Energy California (HECA) Power Plant Project Revised AFC (08-AFC-8). The following documents were also reviewed:

- "Responses to CEC Data Requests Set One (#1-132)" dated November 2009
- "Responses to CEC Data Requests Set One (#1, 2, 11, 17, 31b, 32, 33, 36, 64f, 85 through 90, and 125 through 132)" dated January 2010
- "Responses to CEC Data Requests Set One #17, 65, 77, and 85 through 90)" dated January 2010
- "Responses to CEC Data Requests Set Two (#133 through 152)" dated January 2010
- Modeling files provided by the applicant, dated January 2010, were also evaluated.

The risk assessment appears to be complete, transparent, and the results were verified in staff's analysis. This health risk assessment can be used to support staff's opinion that the proposed project will not result in a significant risk to public health.

The most significant emission source for the proposed project is the CTG/HRSG train. According to Section 5.6.2.3 of the AFC, emission rates of toxic air contaminants (TACs) from the CTG were determined based on firing of hydrogen-rich fuel under operating conditions determined in Section 5.1, Air Quality, to result in the highest off-site ground-level impacts. It should be noted that Table 5.6-2, HRSG Combustion Turbine (GE7FB) Stack TACs Emission Rates (Response to Data Request 89, dated January 2010), indicates the source to be the HECA project itself and also states that emission rates are taken from "Wabash River test data and the National Energy Technology Laboratory, U.S. Dept of Energy, Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report, December 2002." Staff is not familiar with this facility but queried the applicant about the comparability of the processes and TAC emissions and staff is satisfied that a report prepared by the US Dept. of Energy could serve as the basis for emission factors. Staff has no evidence to refute the validity and appropriateness of this data.

Construction Phase Analysis

For the construction phase analysis, atmospheric dispersion modeling of diesel particulate matter (DPM) emissions from construction equipment and vehicles was conducted by the applicant using AERMOD. The maximum predicted offsite concentration of diesel particulate matter, on a 70-year basis, was reported by the applicant to be 0.29503 ug/m^3 (Table 85-1 of the January 2010 response to comments).

Cancer risk and chronic hazard index values obtained by staff are compared to results reported by the applicant in the January 2010 modeling files in **Public Health Table 5**. Cancer risk due to diesel exhaust emissions was determined by multiplying the DPM concentration by the diesel cancer inhalation unit risk of 0.0003 $(ug/m^3)^{-1}$ and adjusting by the estimated construction period of 4 years over a 70 year lifetime for residential receptors.

Operations Phase Analysis

For the operations phase analysis, atmospheric dispersion modeling of facility emissions was conducted by the applicant using AERMOD. Local meteorological data were used, building downwash effects were included for 41 buildings, and 5,543 receptors were modeled.

The 196 emitting units modeled by the applicant include:

- 1 Combustion turbine generator with associated heat steam generator (CTG/HRSG)
- 4 ASU (air separation unit) cooling tower stacks
- 13 Power block cooling tower stacks
- 4 Gasification cooling tower stacks
- 1 Emergency diesel generator
- 1 Emergency firewater pump diesel engine
- 1 Auxiliary boiler
- 1 Tail gas thermal oxidizer
- 1 SRU (sulfur recovery unit) flare
- 1 Gasification flare
- 1 Gasifier warming vent
- 6 Feedstock dust collection locations (no toxic air contaminant emissions associated with this source)
- 1 Rectisol flare
- 85 Feedstock coke and coal delivery trucks
- 50 Gasifier solids handling trucks (for removal of gasifier solids)
- 1 Idling of feedstock coke and coal trucks
- 1 Idling of gasifier solids handling trucks at pickup
- 1 Idling of gasifier solids handling trucks at drop-off
- 2 Power block fugitive sources
- 3 SRU (sulfur recovery unit) fugitives
- 3 SWS (sour water stripper) fugitives
- 3 TGTU (tail gas treating unit) fugitives

- 5 Gasification fugitives
- 2 Shift fugitives
- 1 CO_2 vent
- 3 AGR (acid gas removal) fugitives
- Total of 196 emitting units

Feedstocks proposed to be used in the proposed facility include petroleum coke, western bituminous coal, fluxant (crushed aggregate, rock or sand), and natural gas. Emission factors obtained from the applicant's data response #89 and from the applicant's modeling files were used in this analysis and are listed in **Public Health Tables 6 and 7**.

Staff used the HARP On-Ramp program to load the applicant's AERMOD results into the CARB/OEHHA Hotspots Analysis and Reporting Program (HARP), Version 1.4a for the risk analysis. Staff initially encountered a bug in the HARP On-Ramp program in conducting its analysis, however, the correct output file was provided to staff for use in the HARP modeling by the applicant (Mitchell 2010).

Exposure pathways assessed include inhalation, ingestion of home-grown produce, ingestion of locally raised pigs, chickens and eggs, dermal absorption, soil ingestion and mother's milk. For risk calculations using the HARP model, the "Derived (Adjusted) Method" was used for cancer risk and the "Derived (OEHHA) Method" was used for chronic noncancer hazard.

Cancer risk and chronic and acute hazard index values obtained by staff are compared to results reported by the applicant in the January 2010 modeling files in **Public Health Table 8**. Risk and hazard were determined at the point of maximum impact (PMI) under the 70 year residential scenario. The PMI is located at the approximate southeast corner of the property. Two nearby residences are also evaluated, one located at the northwest corner of the property and one located approximately 1,300 feet east of the property, at Station Road and Tule Park Road. The maximum exposed worker is located at the Tule Elk Sate Reserve Station, approximately 3,900 feet east of the property and the nearest sensitive receptor is at the Elk Hills School in Tupman located approximately 12,000 feet southeast of the site.

Public Health Table 9 presents substance- and source-specific cancer risks at the PMI from staff's modeling. Analysis of this table indicates that 95% of the cancer risk at the PMI is attributed to emissions from the CTG/HRSG. Additional analysis indicates that 44% of cancer risk at the PMI is attributed to arsenic, 33% to cadmium, 18% from hexavalent chromium and 3% from diesel particulate matter.

Public Health Table 5.
Results of Staff's Analysis and the Applicant's Analysis for Cancer Risk and Chronic Hazard during Construction Phase.

		Staff's Analysis		**Applicant's Analysis**	
	Annual PM10 Concentration (ug/m^3)	Cancer Risk (per million)	Chronic HI	Cancer Risk (per million)	Chronic HI
PMI	0.29503	5.1	0.06	7.0	0.06
MEIW	0.01325	0.13	0.003	0.08	0.003
MEIR-1	0.05441	0.93	0.011	1.29	0.011
Nearest school	0.00910	0.16	0.002	0.22	0.002

Note:
PMI = point of maximum impact (or maximally impacted receptor, MIR); the PMI for cancer risk and chronic hazard index is located southeast of the property, Receptor #135 (UTM coordinates 283960E, 3911650N)
MEIW = maximally exposed individual, worker is located east of the property at the Tule Elk State Reserve Ranger Station, Receptor #5495 (UTM coordinates 285170E, 3912389N); evaluated under the worker exposure scenario (10 hours/day, 250 days/year, 35 years)
MEIR-1 = maximally exposed individual, residential is located at the northwest corner of the property, Receptor #5496 (UTM coordinates 282408E, 3913181N)
Nearest school = located at Elk Hills School in Tupman, Rec #5494 (UTM coordinates 285878E, 3908605N)

Public Health Table 6.
Operation Phase Annual Emission Rates (lb/yr)

Substance	CTG/HRSG	ASU Cooling Tower (each of 4 units)	Power Block Cooling Tower (each of 13 units)	Gasification Cooling Tower (each of 4 units)
Annual Emissions (lb/yr)				
Acetaldehyde	3.64E+01			
Antimony	2.23E+01			
Arsenic	4.86E+01	5.38E-03	7.21E-03	5.67E-03
B[a]anthracene	4.66E-02			
Benzene	4.86E+01			
Beryllium	5.26E+00			
Cadmium	1.94E+02			
Chromium	1.03E+01			
Cobalt	5.26E+00			
Copper		1.05E-03	1.40E-03	1.10E-03
Cr(VI)	3.10E+00			
CS2	9.31E+02			
Cyanide cmpds	1.15E+02			
Fluorides&cmpds		9.41E-02	1.26E-01	9.90E-02
Formaldehyde	3.44E+02			
HCl	2.63E+02			
HF	1.01E+03			
Lead	1.13E+01			
Manganese	2.11E+01	2.69E-01	3.60E-01	2.83E-01
Mercury	2.43E+01			
Methyl Bromide	9.66E+02			
Methylene Chlor	4.45E+01			
Naphthalene	5.06E+01			
NH3	1.53E+05			
Nickel	7.90E+00			
Phenol	7.45E+02			
Selenium	1.13E+01	4.47E-03	5.99E-03	4.71E-03
Sulfuric Acid	1.16E+04			
Toluene	6.68E-01			
Zinc		2.09E-03	2.80E-03	2.20E-03

Source: Applicant's modeling files dated January 2010

Public Health Table 6 (continued).
Operation Phase Annual Emission Rates (lb/yr)

Substance	Auxiliary Boiler	Tail Gas Thermal Oxidizer	Gasifier Warming Vent B	Rectisol Flare
Annual Emissions (lb/yr)				
2MeNaphthalene	7.11E-03	2.00E-03	7.41E-04	6.18E-05
3-MeCholanthren	5.33E-04	1.50E-04	5.55E-05	4.60E-06
7,12-DB[a]anthr	4.74E-03	1.33E-03	4.94E-04	4.12E-05
Acenaphthene	5.33E-04	1.50E-04	5.55E-05	4.60E-06
Acenaphthylene	5.33E-04	1.50E-04	5.55E-05	4.60E-06
Anthracene	7.11E-04	2.00E-04	7.41E-05	6.20E-06
Arsenic	5.92E-02	1.67E-02	6.17E-03	5.15E-04
B[a]anthracene	5.33E-04	1.50E-04	5.55E-05	4.60E-06
B[a]P				3.10E-06
B[b]fluoranthene	5.33E-04	1.50E-04	5.55E-05	4.60E-06
B[e]pyrene	3.55E-04	1.00E-04	3.70E-05	
B[g,h,i]perylen	3.55E-04	1.00E-04	3.70E-05	3.10E-06
B[j]fluoranthen				4.60E-06
B[k]fluoranthene	5.33E-04	1.50E-04	5.55E-05	
Barium				1.13E-02
Benzene	6.22E-01	1.75E-01	6.48E-02	5.41E-03
Beryllium	3.55E-03	1.00E-03	3.70E-04	3.09E-05
Cadmium	3.26E-01	9.18E-02	3.39E-02	2.83E-03
Chromium	4.15E-01	1.17E-01	4.32E-02	3.61E-03
Chrysene	5.33E-04	1.50E-04	5.55E-05	4.60E-06
Cobalt	2.49E-02	7.01E-03	2.59E-03	2.16E-04
Copper	2.52E-01	7.09E-02	2.62E-02	2.19E-03
D[a,h]anthracene	3.55E-04	1.00E-04	3.70E-05	3.10E-06
DiClBenzenes				3.09E-03
Fluoranthene	8.89E-04	2.50E-04	9.26E-05	7.70E-06
Fluorene	8.29E-04	2.34E-04	8.64E-05	7.20E-06
Formaldehyde	2.22E+01	6.26E+00	2.31E+00	1.93E-01
Hexane	5.33E+02	1.50E+02	5.55E+01	4.64E+00
In[1,2,3-cd]pyralene	5.33E-04	1.50E-04	5.55E-05	4.60E-06
Manganese	1.13E-01	3.17E-02	1.17E-02	9.79E-04
Mercury	7.70E-02	2.17E-02	8.02E-03	6.70E-04
Naphthalene	1.81E-01	5.09E-02	1.88E-02	1.57E-03
Nickel	6.22E-01	1.75E-01	6.48E-02	5.41E-03
Phenanthrene	5.03E-03	1.42E-03	5.25E-04	4.38E-05
Pyrene	1.48E-03	4.17E-04	1.54E-04	1.29E-05
Selenium	7.11E-03	2.00E-03	7.41E-04	6.18E-05
Toluene	1.01E+00	2.84E-01	1.05E-01	8.76E-03
Vanadium	6.81E-01	1.92E-01	7.10E-02	5.93E-03
Zinc				7.47E-02

Source: Applicant's modeling files dated January 2010

Public Health Table 6 (continued).
Operation Phase Annual Emission Rates (lb/yr)

Substance	SRU Flare	Gasification Flare	Diesel Emergency Generator	Diesel Firepump
Annual Emissions (lb/yr)				
Acetaldehyde	1.16E-01	4.91E+00		
Acrolein	2.71E-02	1.14E+00		
Arsenic	5.42E-04	2.28E-02		
Benzene	4.31E-01	1.82E+01		
Beryllium	3.25E-05	1.37E-03		
Cadmium	2.98E-03	1.26E-01		
Chromium	3.79E-03	1.60E-01		
Cobalt	2.28E-04	9.59E-03		
Copper	2.30E-03	9.70E-02		
DieselExhPM			2.30E+01	1.84E+00
Ethyl Benzene	3.91E+00	1.65E+02		
Formaldehyde	3.17E+00	1.33E+02		
Hexane	7.85E-02	3.31E+00		
Lead	1.35E-03	5.71E-02		
Manganese	1.03E-03	4.34E-02		
Mercury	7.04E-04	2.97E-02		
Naphthalene	2.98E-02	1.26E+00		
Nickel	5.69E-03	2.40E-01		
PAHs-w/o	8.13E-03	3.43E-01		
Propylene	6.61E+00	2.79E+02		
Selenium	6.50E-05	2.74E-03		
Toluene	1.57E-01	6.62E+00		
Vanadium	6.23E-03	2.63E-01		
Xylenes	7.85E-02	3.31E+00		
Zinc	7.85E-02	3.31E+00		

Source: Applicant's modeling files dated January 2010

Public Health Table 6 (continued).
Operation Phase Annual Emission Rates (lb/yr)

Substance	Power Block Fugitives (2 sources)	Sour Water Stripper (SWS) Fugitives (3 sources)	Gasification Fugitives (5 sources)	SRU Fugitives (3 sources)
Annual Emissions (lb/yr)				
H2S	6.48E+01	3.33E+01	3.91E+02	3.08E+02
HCN	5.10E-01		1.79E+00	
Methanol				2.70E-01
NH3	7.98E+01	4.57E+01	3.62E+00	

Substance	Tail Gas Treating Unit Fugitives (3 sources)	Shift Fugitives (2 sources)	CO2 Vent	Acid Gas Removal Fugitives (3 sources)
Annual Emissions (lb/yr)				
H2S	1.88E+02	5.07E+02	2.60E+03	
Methanol	4.33E+03			
Propylene				3.94E+03

Substance	Feedstock Coke and Coal Trucks (85 sources)	Gasifier Solids Handling Trucks (50 sources)	Idling of Feedstock Coke and Coal Trucks (1 source)	Idling of Gasifier Solids Handling Trucks at Pickup (1 source)	Idling of Gasifier Solids Handling Trucks at Drop-off (1 source)
Annual Emissions (lb/yr)					
DieselExhPM	7.30E-02	3.90E-03	1.30E-02	7.70E-04	7.70E-04

Source: Applicant's modeling files dated January 2010

Public Health Table 7.
Operation Phase Maximum Emission Rates (lb/hr)

Substance	CTG/HRSG	ASU Cooling Tower (each of 4 units)	Power Block Cooling Tower (each of 13 units)	Gasification Cooling Tower (each of 4 units)
Annual Emissions (lb/hr)				
Acetaldehyde	4.41E-03			
Antimony	2.69E-03			
Arsenic	5.88E-03	6.47E-07	8.67E-07	6.81E-07
B[a]anthracene	5.63E-06			
Benzene	5.88E-03			
Beryllium	6.37E-04			
Cadmium	2.35E-02			
Chromium	1.25E-03			
Cobalt	6.37E-04			
Copper		1.26E-07	1.68E-07	1.32E-07
Cr(VI)	3.75E-04			
CS2	1.13E-01			
Cyanide cmpds	1.40E-02			
Fluorides&cmpds		1.13E-05	1.51E-05	1.19E-05
Formaldehyde	4.16E-02			
HCl	3.18E-02			
HF	1.22E-01			
Lead	1.37E-03			
Manganese	2.55E-03	3.23E-05	4.33E-05	3.40E-05
Mercury	2.94E-03			
Methyl Bromide	1.17E-01			
Methylene Chlor	5.39E-03			
Naphthalene	6.13E-03			
NH3	1.84E+01			
Nickel	9.55E-04			
Phenol	9.01E-02			
Selenium	1.37E-03	5.38E-07	7.20E-07	5.66E-07
Sulfuric Acid	1.40E+00			
Toluene	8.08E-05			
Zinc		2.51E-07	3.37E-07	2.64E-07

Source: Applicant's modeling files dated January 2010

Public Health Table 7 (continued).
Operation Phase Maximum Emission Rates (lb/hr)

Substance	Auxiliary Boiler	Tail Gas Thermal Oxidizer	Gasifier Warming Vent B	Rectisol Flare
Annual Emissions (lb/hr)				
2MeNaphthalene	3.25E-06	2.29E-07	4.11E-07	7.00E-09
3-MeCholanthren	2.43E-07	1.70E-08	3.10E-08	1.00E-09
7,12-DB[a]anthr	2.16E-06	1.52E-07	2.74E-07	5.00E-09
Acenaphthene	2.43E-07	1.70E-08	3.10E-08	1.00E-09
Acenaphthylene	2.43E-07	1.70E-08	3.10E-08	1.00E-09
Anthracene	3.25E-07	2.30E-08	4.10E-08	1.00E-09
Arsenic	2.70E-05	1.90E-06	3.43E-06	5.90E-08
B[a]anthracene	2.43E-07	1.70E-08	3.10E-08	1.00E-09
B[a]P				
B[b]fluoranthen	2.43E-07	1.70E-08	3.10E-08	1.00E-09
B[e]pyrene	1.62E-07	1.10E-08	2.10E-08	
B[g,h,i]perylen	1.62E-07	1.10E-08	2.10E-08	
B[j]fluoranthen				1.00E-09
B[k]fluoranthen	2.43E-07	1.70E-08	3.10E-08	
Barium				1.29E-06
Benzene	2.84E-04	2.00E-05	3.60E-05	6.18E-07
Beryllium	1.62E-06	1.14E-07	2.06E-07	4.00E-09
Cadmium	1.49E-04	1.05E-05	1.89E-05	3.24E-07
Chromium	1.89E-04	1.33E-05	2.40E-05	4.12E-07
Chrysene	2.43E-07	1.70E-08	3.10E-08	1.00E-09
Cobalt	1.14E-05	8.00E-07	1.44E-06	2.50E-08
Copper	1.15E-04	8.10E-06	1.46E-05	2.50E-07
D[a,h]anthracene	1.62E-07	1.10E-08	2.10E-08	
DiClBenzenes				3.53E-07
Fluoranthene	4.06E-07	2.90E-08	5.10E-08	1.00E-09
Fluorene	3.79E-07	2.70E-08	4.80E-08	1.00E-09
Formaldehyde	1.01E-02	7.14E-04	1.29E-03	2.21E-05
Hexane	2.43E-01	1.71E-02	3.09E-02	5.29E-04
In[1,2,3-cd]pyralene	2.43E-07	1.70E-08	3.10E-08	1.00E-09
Manganese	5.14E-05	3.62E-06	6.51E-06	1.12E-07
Mercury	3.52E-05	2.48E-06	4.46E-06	7.60E-08
Naphthalene	8.25E-05	5.81E-06	1.05E-05	1.79E-07
Nickel	2.84E-04	2.00E-05	3.60E-05	6.18E-07
Phenanthrene	2.30E-06	1.62E-07	2.91E-07	5.00E-09
Pyrene	6.76E-07	4.80E-08	8.60E-08	1.00E-09
Selenium	3.25E-06	2.29E-07	4.11E-07	7.00E-09
Toluene	4.60E-04	3.24E-05	5.83E-05	1.00E-06
Vanadium	3.11E-04	2.19E-05	3.94E-05	6.76E-07
Zinc				8.53E-06

Source: Applicant's modeling files dated January 2010

Public Health Table 7 (continued).
Operation Phase Maximum Emission Rates (lb/hr)

Substance	SRU Flare	Gasification Flare	Diesel Emergency Generator	Diesel Firepump
Annual Emissions (lb/hr)				
Acetaldehyde	1.49E-03	9.07E-02		
Acrolein	3.46E-04	2.11E-02		
Arsenic	6.91E-06	4.22E-04		
Benzene	5.50E-03	3.35E-01		
Beryllium	4.15E-07	2.53E-05		
Cadmium	3.80E-05	2.32E-03		
Chromium	4.84E-05	2.95E-03		
Cobalt	2.90E-06	1.77E-04		
Copper	2.94E-05	1.79E-03		
DieselExhPM			4.60E-01	1.84E-02
Ethyl Benzene	4.99E-02	3.05E+00		
Formaldehyde	4.04E-02	2.47E+00		
Hexane	1.00E-03	6.12E-02		
Lead	1.73E-05	1.05E-03		
Manganese	1.31E-05	8.02E-04		
Mercury	8.99E-06	5.49E-04		
Naphthalene	3.80E-04	2.32E-02		
Nickel	7.26E-05	4.43E-03		
PAHs-w/o	1.04E-04	6.33E-03		
Propylene	8.44E-02	5.15E+00		
Selenium	8.30E-07	5.06E-05		
Toluene	2.01E-03	1.22E-01		
Vanadium	7.95E-05	4.84E-03		
Xylenes	1.00E-03	6.12E-02		
Zinc	1.00E-03	6.12E-02		

Source: Applicant's modeling files dated January 2010

Public Health Table 7 (continued).
Operation Phase Maximum Emission Rates (lb/hr)

Substance	Power Block Fugitives (2 sources)	Sour Water Stripper (SWS) Fugitives (3 sources)	Gasification Fugitives (5 sources)	SRU Fugitives (3 sources)
Annual Emissions (lb/hr)				
H2S	7.40E-03	3.80E-03	4.46E-02	3.51E-02
HCN	6.00E-05		2.00E-04	
Methanol				3.00E-05
NH3	9.11E-03	5.22E-03	4.10E-04	

Substance	Tail Gas Treating Unit Fugitives (3 sources)	Shift Fugitives (2 sources)	CO2 Vent	Acid Gas Removal Fugitives (3 sources)
Annual Emissions (lb/hr)				
H2S	2.14E-02	5.79E-02	5.15E+00	
Methanol	4.94E-01			
Propylene				4.50E-01

Substance	Feedstock Coke and Coal Trucks (85 sources)	Gasifier Solids Handling Trucks (50 sources)	Idling of Feedstock Coke and Coal Trucks (1 source)	Idling of Gasifier Solids Handling Trucks at Pickup (1 source)	Idling of Gasifier Solids Handling Trucks at Drop-off (1 source)
Annual Emissions (lb/hr)					
DieselExhPM	3.70E-05	2.70E-06	6.60E-06	5.30E-07	5.30E-07

Source: Applicant's modeling files dated January 2010

Public Health Table 8.
Results of Staff's Analysis and the Applicant's Analysis for Cancer Risk and Chronic and Acute Hazard during Operations Phase.

	Staff's Analysis			Applicant's Analysis		
	Cancer Risk (per million)	Chronic HI	Acute HI	Cancer Risk (per million)	Chronic HI	Acute HI
PMI	3.02	0.27	0.79	3.02	0.27	0.79
MEIW	0.082	0.035	0.11	0.082	0.035	0.11
MEIR-1	0.72	0.060	0.22	0.72	0.060	0.22
MEIR-2	0.59	0.052	0.16	0.59	0.052	0.16
Nearest school	0.43	0.038	0.10	0.43	0.038	0.10

Note:
PMI = point of maximum impact (or maximally impacted receptor, MIR); the PMI for cancer risk and chronic hazard index is located southeast of the property, Receptor #135 (UTM coordinates 283960E, 3911650N); the PMI for acute hazard is located southwest of the property, Receptor #254 (282674E, 3911504N)
MEIW = maximally exposed individual, worker is located east of the property at the Tule Elk State Reserve Ranger Station, Receptor #5495 (UTM coordinates 285170E, 3912389N); evaluated under the worker exposure scenario
MEIR-1 = maximally exposed individual, residential is located at the northwest corner of the property, Receptor #5496 (UTM coordinates 282408E, 3913181N)
MEIR-2 = maximally exposed individual, residential is located east of the property at Station Road and Tule Park Road, Receptor #5493 (UTM coordinates 284396E, 3912529N)
Nearest school = located at Elk Hills School in Tupman, Rec #5494 (UTM coordinates 285878E, 3908605N)

Public Health Table 9.

Results of Staff's Analysis: Contribution to Total Cancer Risk by Individual Substances from All Sources at the Point of Maximum Impact (PMI).

Substance	CTG HRSG	ASU Cooling Tower (4 units)	Power Block Cooling Tower (13 units)	Gasifi-cation Cooling Tower (4 units)	Auxiliary Boiler	Tail Gas Thermal Oxidizer	Gasifier Warming Vent B
3-MeCholanthren					2.41E-10	5.80E-11	4.55E-11
7,12-DB[a]anthr					2.43E-08	5.85E-09	4.60E-09
Acetaldehyde	1.23E-10						
Arsenic	1.31E-06	1.51E-09	1.35E-08	3.66E-09	4.96E-09	1.20E-09	9.37E-10
B[a]anthracene	3.59E-10				1.27E-11	3.07E-12	2.40E-12
B[a]P							
B[b]fluoranthen					1.27E-11	3.07E-12	2.40E-12
B[j]fluoranthen							
B[k]fluoranthen					1.27E-11	3.07E-12	2.40E-12
Benzene	1.65E-09				6.53E-11	1.57E-11	1.23E-11
Beryllium	1.50E-08				3.13E-11	7.55E-12	5.91E-12
Cadmium	9.86E-07				5.13E-09	1.24E-09	9.67E-10
Chrysene					1.27E-12	3.07E-13	2.40E-13
Cr(VI)	5.36E-07						
D[a,h]anthracene					2.99E-11	7.21E-12	5.65E-12
DieselExhPM							
Ethyl Benzene							
Formaldehyde	2.45E-09				4.89E-10	1.18E-10	9.23E-11
In[1,2,3-cd]pyralene					1.27E-11	3.07E-12	2.40E-12
Lead	1.08E-09						
Methylene Chlor	5.28E-11						
Naphthalene	2.06E-09				2.28E-11	5.49E-12	4.29E-12
Nickel	2.44E-09				5.94E-10	1.43E-10	1.12E-10
PAHs-w/o							
SUM	2.86E-06	1.51E-09	1.35E-08	3.66E-09	3.59E-08	8.66E-09	6.79E-09

Public Health Table 9 (continued).
Results of Staff's Analysis: Contribution to Total Cancer Risk by Individual Substances from All Sources at the Point of Maximum Impact (PMI).

Substance	Rectisol Flare	SRU Flare	Gasifi-cation Flare	Diesel Emergenc y. Generator	Diesel Firepump	Feedstock Coke and Coal Trucks (85 sources)	Gasifier Solids Handling Trucks (50 sources)
3-MeCholanthren	1.29E-12						
7,12-DB[a]anthr	1.31E-10						
Acetaldehyde		5.70E-13	5.11E-12				
Arsenic	2.68E-11	2.13E-11	1.90E-10				
B[a]anthracene	6.83E-14						
B[a]P	4.60E-13						
B[b]fluoranthen	6.83E-14						
B[j]fluoranthen	6.83E-14						
B[k]fluoranthen							
Benzene	3.53E-13	2.12E-11	1.90E-10				
Beryllium	1.69E-13	1.34E-13	1.20E-12				
Cadmium	2.77E-11	2.19E-11	1.97E-10				
Chrysene	6.83E-15						
Cr(VI)							
D[a,h]anthracene	1.62E-13						
DieselExhPM				4.34E-08	3.25E-09	2.75E-08	1.85E-09
Ethyl Benzene		1.67E-11	1.49E-10				
Formaldehyde	2.64E-12	3.27E-11	2.91E-10				
In[1,2,3-cd]pyralene	6.83E-14						
Lead		1.87E-13	1.68E-12				
Methylene Chlor							
Naphthalene	1.23E-13	1.76E-12	1.57E-11				
Nickel	3.21E-12	2.54E-12	2.27E-11				
PAHs-w/o		9.09E-10	8.13E-09				
SUM	1.94E-10	1.03E-09	9.19E-09	4.34E-08	3.25E-09	2.75E-08	1.85E-09

Public Health Table 9 (continued).
Results of Staff's Analysis: Contribution to Total Cancer Risk by Individual Substances from All Sources at the Point of Maximum Impact (PMI).

Substance	Idling of Feedstock Coke and Coal Trucks (1 source)	Idling of Gasifier Solids Handling Trucks at Pickup (1 source)	Idling of Gasifier Solids Handling Trucks at Drop-off (1 source)	TOTAL
3-MeCholanthren				3.46E-10
7,12-DB[a]anthr				3.49E-08
Acetaldehyde				1.29E-10
Arsenic				1.34E-06
B[a]anthracene				3.77E-10
B[a]P				4.60E-13
B[b]fluoranthen				1.82E-11
B[j]fluoranthen				6.83E-14
B[k]fluoranthen				1.82E-11
Benzene				1.95E-09
Beryllium				1.50E-08
Cadmium				9.94E-07
Chrysene				1.82E-12
Cr(VI)				5.36E-07
D[a,h]anthracene				4.29E-11
DieselExhPM	6.95E-11	6.95E-12	8.52E-12	7.61E-08
Ethyl Benzene				1.66E-10
Formaldehyde				3.48E-09
In[1,2,3-cd]pyralene				1.82E-11
Lead				1.08E-09
Methylene Chlor				5.28E-11
Naphthalene				2.11E-09
Nickel				3.32E-09
PAHs-w/o				9.04E-09
SUM	6.95E-11	6.95E-12	8.52E-12	3.01E-06

Cooling Towers

In addition to being a source of potential toxic air contaminants, the possibility exists for bacterial growth to occur in the cooling towers, including Legionella. Legionella is a bacterium that is ubiquitous in natural aquatic environments and is also widely distributed in man-made water systems. It is the principal cause of legionellosis, otherwise known as Legionnaires' Disease, which is similar to pneumonia. Transmission to people results mainly from inhalation or aspiration of aerosolized contaminated water. Untreated or inadequately treated cooling systems, such as industrial cooling towers and building heating, ventilating, and air conditioning systems, have been correlated with outbreaks of legionellosis.

Legionella can grow symbiotically with other bacteria and can infect protozoan hosts. This provides Legionella with protection from adverse environmental conditions, including making it more resistant to water treatment with chlorine, biocides, and other

disinfectants. Thus, if not properly maintained, cooling water systems and their components can amplify and disseminate aerosols containing Legionella.
The State of California regulates recycled water for use in cooling towers in Title 22, Section 60303, California Code of Regulations. This section requires that, in order to protect workers and the public who may come into contact with cooling tower mists, chlorine or another biocide must be used to treat the cooling system water to minimize the growth of Legionella and other micro-organisms. This regulation does not apply to the HECA project since it intends to use brackish water provided by the Buena Vista Water Storage District (BVWSD) that would be treated on-site (HEI 2008c, Section 2.1.8.4). However, the potential remains for Legionella growth in cooling water at HECA due to nutrients that are found in groundwater.

The U.S. EPA published an extensive review of Legionella in a human health criteria document (EPA 1999). The U.S. EPA noted that Legionella may propagate in biofilms (collections of microorganisms surrounded by slime they secrete, attached to either inert or living surfaces) and that aerosol-generating systems such as cooling towers can aid in the transmission of Legionella from water to air. The U.S. EPA has inadequate quantitative data on the infectivity of Legionella in humans to prepare a dose-response evaluation. Therefore, sufficient information is not available to support a quantitative characterization of the threshold infective dose of Legionella. Thus, the presence of even small numbers of Legionella bacteria presents a risk - however small - of disease in humans.

In February of 2000 the Cooling Technology Institute (CTI) issued its own report and guidelines for the best practices for control of Legionella (CTI 2000). The CTI found that 40-60% of industrial cooling towers tested were found to contain Legionella. More recently, staff has received a 2005 report of testing in cooling towers in Australia that found the rate of Legionella presence in cooling tower waters to be extremely low, approximately three to 6%. The cooling towers all had implemented aggressive water treatment and biocide application programs similar to that required by proposed condition of certification **Public Health-1**.

To minimize the risk from Legionella, the CTI noted that consensus recommendations included minimization of water stagnation, minimization of process leads into the cooling system that provide nutrients for bacteria, maintenance of overall system cleanliness, the application of scale and corrosion inhibitors as appropriate, the use of high-efficiency mist eliminators on cooling towers, and the overall general control of microbiological populations.

Good preventive maintenance is very important in the efficient operation of cooling towers and other evaporative equipment (ASHRAE 1998). Preventive maintenance includes having effective drift eliminators, periodically cleaning the system if appropriate, maintaining mechanical components in working order, and maintaining an effective water treatment program with appropriate biocide concentrations. Staff notes that most water treatment programs are designed to minimize scale, corrosion, and biofouling and not to control Legionella.

The efficacy of any biocide in ensuring that bacterial and in particular Legionella growth, is kept to a minimum is contingent upon a number of factors including but not limited to proper dosage amounts, appropriate application procedures and effective monitoring.

In order to ensure that Legionella growth is kept to a minimum, thereby protecting both nearby workers as well as members of the public, staff has proposed Condition of Certification **Public Health-1**. The condition would require the project owner to prepare and implement a biocide and anti-biofilm agent monitoring program to ensure that proper levels of biocide and other agents are maintained within the cooling tower water at all times, that periodic measurements of Legionella levels are conducted, and that periodic cleaning is conducted to remove bio-film buildup. Staff believes that with the use of an aggressive antibacterial program coupled with routine monitoring and biofilm removal, the chances of Legionella growing and dispersing would be reduced to insignificance.

ALTERNATIVES

Staff has reviewed four potential alternative sites from the perspective of public health impacts due to emissions of toxic air contaminants from all the sources identified above. Of all possible alternative site locations, none were environmentally superior to the project site and therefore the project site was selected (HEI 2008c, Section 6.3.1). Because the cancer risk and hazard indices are very much below the level of significance at the point of maximum impact, staff believes that regardless of the exact location of this proposed intergrated gasification combined cycle facility within this region, the project would not pose a significant risk to public health. Therefore, staff concludes that there is no preferable alternative location for public health.

CUMULATIVE IMPACTS AND MITIGATION

A project may result in a significant adverse cumulative impact where its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (California Code Regulation, Title 14, section 15130). NEPA states that cumulative effects can result from individually minor but collectively significant actions taking place over a period of time" (40 CFR §1508.7).

Cumulative impacts of the proposed project and other projects within a 6-mile radius were not evaluated in the AFC. The applicant stated that there are no existing or planned TAC emission sources in the project vicinity that could contribute to a public health cumulative impact (HEI 2008c, Section 5.6.3).

The maximum cancer risk for operations emissions from the HECA project (calculated by staff) is 3.0 in one million, which is below the level of significance. Similarly, the maximum chronic HI calculated by staff is 0.27and the maximum acute HI is 0.79 which is at a location southwest of the property in an open area; the acute HI at the nearest residence is 0.22. Staff has found that while air quality cumulative impacts can occur with sources within a 6-mile radius, cumulative public health impacts are not significant unless the emitting sources are extremely close to each other, with a few blocks, not miles. Staff therefore concludes that the proposed HECA project would not contribute to cumulative impacts in the area of public health.

COMPLIANCE WITH LORS

Staff has considered the minority population as identified in **Socioeconomics Figure 1** in its impact analysis and has found no potential significant adverse impacts for any receptors, including environmental justice populations. In arriving at this conclusion, staff notes that its analysis complies with all directives and guidelines from the Cal/EPA Office of Environmental Health Hazard Assessment and the California Air Resources Board. Staff's assessment is biased toward the protection of public health and takes into account the most sensitive individuals in the population. Using extremely conservative (health-protective) exposure and toxicity assumptions, staff's analysis demonstrates that members of the public potentially exposed to toxic air contaminant emissions of this project—including sensitive receptors such as the elderly, infants, and people with pre-existing medical conditions—will not experience any acute or chronic significant health risk or any significant cancer risk as a result of that exposure. Staff believes that it incorporated every conservative assumption called for by state and federal agencies responsible for establishing methods for analyzing public health impacts. The results of that analysis indicate that there would be no direct or cumulative significant public health impact to any population in the area. Therefore, given the absence of any significant health impacts, there are no disparate health impacts and there are no environmental justice issues associated with **PUBLIC HEALTH**.

Staff concludes that construction and operation of the HECA will be in compliance with all applicable LORS regarding long-term and short-term project impacts in the area of **PUBLIC HEALTH**.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

None Received.

CONCLUSIONS

Staff has analyzed potential public health risks associated with construction and operation of the HECA project and does not expect any significant adverse cancer, short-term, or long-term health effects to any members of the public, including low income and minority populations, from project toxic emissions. Staff also concludes that its analysis of potential health impacts from the proposed HECA uses a conservative health-protective methodology that accounts for impacts to the most sensitive individuals in a given population, including newborns and infants. According to the results of staff's health risk assessment, emissions from the HECA would not contribute significantly or cumulatively to morbidity or mortality in any age or ethnic group residing in the project area.

PROPOSED CONDITIONS OF CERTIFICATION

Public Health-1 The project owner shall develop and implement a Cooling Water Management Plan to ensure that the potential for bacterial growth in cooling water is kept to a minimum. The Plan shall be consistent with either staff's "Cooling Water Management Program Guidelines" or with the Cooling Technology Institute's "Best Practices for Control of Legionella" guidelines but in either case, the Plan must include sampling and testing for the presence of Legionella bacteria at least every six months. After two years of power plant operations, the project owner may ask the CPM to re-evaluate and revise the Legionella bacteria testing requirement.

Verification: At least 60 days prior to the commencement of cooling tower operations, the Cooling Water Management Plan shall be provided to the CPM for review and approval.

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SOCIOECONOMICS

Scott Debauche

SUMMARY OF CONCLUSIONS

California Energy Commission (Energy Commission) staff concludes that the approximately 250 MW Integrated Gasification Combined Cycle power generating facility, referred to as the Hydrogen Energy California project (HECA or proposed project), would not result in significant adverse direct or indirect socioeconomics impacts because the construction and operation workforce required for the proposed HECA project largely resides in the regional or local labor market area. In addition, the HECA project would not contribute to a cumulative socioeconomic impact on the area's population, employment, housing, police, schools, or hospitals. The construction and operation of the proposed project would not result in any disproportionate adverse socioeconomic impacts to any low-income or minority population. Gross public benefits from the HECA include capital costs and sales taxes as well as the generation of secondary jobs and income.

INTRODUCTION

The socioeconomics impact analysis evaluates project-related changes on existing population and employment patterns, and community services. In addition, this section provides demographic information related to environmental justice. A discussion of the estimated beneficial economic impacts of the construction and operation of the proposed HECA and other related socieconomic impacts are provided.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

SOCIOECONOMICS Table 1 contains socioeconomics laws, ordinances, regulations, and standards (LORS) applicable to the proposed project.

SOCIOECONOMICS Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
State	
California Education Code, Section 17620	The governing board of any school district is authorized to levy a fee, charge, dedication, or other requirement for the purpose of funding the construction or reconstruction of school facilities.
California Government Code, Sections 65996-65997	Except for a fee, charge, dedication, or other requirement authorized under Section 17620 of the Education Code, state and local public agencies may not impose fees, charges, or other financial requirements to offset the cost for school facilities.
Local	**None**

SETTING

The 473-acre HECA 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. Kern County is located in the southern Central Valley of the state of California, northeast of the Los Angeles area. The proposed project site is located near a hydrocarbon-producing area known as the Elk Hills Field. The HECA site is currently used primarily for agricultural purposes. Adjacent land uses include Adohr Road and agricultural uses to the north; Tupman Road and agricultural uses to the east, agricultural uses and an irrigation canal to the south; and a residence, structures (used for grain storage and organic fertilizer production), agricultural uses, and Dairy Road to the west.

DEMOGRAPHIC SCREENING

The demographic screening process is conducted based on information contained in two documents: *Environmental Justice: Guidance Under the National Environmental Policy Act* (Council on Environmental Quality 1997) and *Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses* (Council on Environmental Quality 1998). Based on the demographic screening analysis, the potential affected area is a six-mile radius of the proposed HECA site. The six-mile radius is consistent with the radius used in the Air Quality section of this document to determine potential air quality impacts. The screening process relies on Year 2000 U.S. Census data to determine levels of minority and below-poverty-level populations.

Minority Populations

According to *Environmental Justice: Guidance Under the National Environmental Policy Act*, minority individuals are defined as members of the following groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic. A minority population, for the purposes of environmental justice, is identified when the minority population of the potentially affected area is (1) greater than 50%; (2) meaningfully greater than the percentage of the minority population in the general population or other appropriate unit of geographical analysis; or (3) when one or more U.S. Census blocks in the potentially affected area have a minority population of greater than 50%.

For the HECA project, the total population within a six-mile radius of the proposed site is 1,686 persons, and the total minority population is 893 persons or 52.93% of the total population (see **SOCIOECONOMICS Figure 1**). As the demographic screening area as a whole does exceed 50.0%, as shown in **SOCIOECONOMICS Figure 1,** staff in several technical areas identified in the Executive Summary of this Staff Assessment has considered environmental justice in their environmental impact analyses.

Below-Poverty-Level Populations

Staff normally identifies the below-poverty-level population within the 6-mile radius using Year 2000 U.S. Census block group data. However, for this project the poverty data would be inaccurate for the 6-mile radius because the census block groups are so large that they include persons well beyond the 6-mile radius and therefore, would misrepresent the poverty data within the 6-mile radius.

ASSESSMENT OF IMPACTS

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff uses Appendix G (Environmental Checklist Form) of the California Environmental Quality Act (CEQA) Guidelines to determine whether project-related socioeconomic impacts would be significant (see **SOCIOECONOMICS Table 2**). As required by the guidelines, staff determines a project's potentially significant impact on population, housing, recreation, and emergency medical and public services by evaluating the impact of the project on those areas.

Criteria for subject areas such as utilities, fire protection, water supply, and wastewater disposal are analyzed in the **Reliability, Worker Safety and Fire Protection,** and **Soils and Water Resources** sections of this document, respectively. Impacts on housing, parks and recreation, schools, medical services, law enforcement, and cumulative impacts are based on subjective judgments, input from local and state agencies, and available data of these socioeconomic resources and service levels. Typically, employment of large numbers of workers from regions outside the study area resulting in population inmigration could potentially result in significant adverse socioeconomic impacts.

SOCIOECONOMICS Table 2
CEQA Environmental Checklist Form

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
POPULATION AND HOUSING —Would the project:				
A. Induce substantial population growth in a new area, either directly or indirectly.				X
B. Displace substantial numbers of existing housing, necessitating the construction of replacement housing elsewhere?				X
C. Displace substantial numbers of people, necessitating construction of replacement housing elsewhere?				X
PUBLIC SERVICES —Would the project:				
D. Result in substantial adverse physical impacts associated with the provision of new or physically altered government facilities, need for new of physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service rations, response times, or other performance objectives for any of the public services: -Emergency medical services -Police protection -Schools -Parks				 X X X X
RECREATION—Would the project:				
A. Increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated? B. Does the project include recreational facilities or require the construction or expansion of recreational facilities which might have an adverse physical effect on the environment?				X X

DIRECT/INDIRECT IMPACTS AND MITIGATION

Induce Substantial Population Growth

To characterize the existing and projected future population profile of the project area, staff summarized the current and forecasted population trends for the Kern County and the city of Bakersfield (part of Kern County) in **SOCIOECONOMICS Table 3**. As shown in **Table 3**, between the period of 2009 and 2030, Kern County is expected to grow in excess of 1.3 million persons. As shown, the city of Bakersfield account for approximately 40% of the Kern County Year 2009 total population.

SOCIOECONOMICS Table 3
Population Profile of the Study Area, Year 2009–2020

Area	2009 Population	2020 Projected Population	2030 Projected Population
City of Bakersfield	333,719	N/A	N/A
Kern County	827,173	1,086,113	1,352,627

N/A: Data Not Available
Source: DOFa 2009; DOFb 2009

For the purpose of this analysis, staff defines "induce substantial population growth" as workers permanently moving into the project area because of project construction and operation, thereby encouraging construction of new homes or extension of roads or other infrastructure. To determine whether the project would induce population growth, staff analyzes the availability of the local workforce and the population within the region. Staff defines "local workforce" for the HECA project to be the Bakersfield Metropolitan Statistical Area (MSA), which includes all of Kern County.[1]

As stated in the Application for Certification (AFC) Section 2.0 (Project Description), the applicant expects that construction of the proposed HECA project would last approximately three years, starting in 2011 and ending in 2014. There would be an average of approximately 740 daily construction workers, with a peak daily workforce of 1,482 during month 24 of construction (HEI 2008c, p. 2-79). This peak employment number is used to analyze worst-case construction population and employment impacts. **SOCIOECONOMICS Table 4** shows California Economic Development Department (EDD) Year 2006-2016 occupational employment projections for the Bakersfield MSA (Kern County) by construction labor skill as compared to the estimated number of total construction workers by craft needed during the peak month (month 24) as presented in the AFC (HEI 2008c, p. 2-79).

[1] Metropolitan Statistical Areas are geographic entities defined by the U.S. Office of Management and Budget (OMB) for use by Federal and State statistical agencies in collecting, tabulating, and publishing socioeconomic statistics.

SOCIOECONOMICS Table 4
Total Labor by Skill in Bakersfield MSA (2006 and 2016 Estimate) and HECA Required Construction by Craft – Peak Month

Trade	Bakersfield MSA 2006	Bakersfield MSA 2016	Total # of Workers for Project Construction – Peak Month
Construction	19,120[1]	21,310[1]	113[2]
Carpenter	2,740	3,060	128
Cement Masons	990	1,100	13
Electricians	2,350	2,580	154
Insulation Workers	100	110	0
Ironworkers	250	260	149
Millwrights	130	160	62
Operators	1,500	1,570	94
Painters	990	1,120	0
Pipefitter	1,340	1,530	496
Sheet Metal Workers	280	300	3
Teamsters	N/A	N/A	5
Off Plot Construction Craft	N/A	N/A	15

Source: EDD 2009.
[1] The "Construction Trades Workers" category was used, of which both "contractor staff" and "boilermakers" are considered a part of. These numbers overstate the actual number of both contractor staff and boilermakers, but were the only number available, as both the "Contractor Staff" and "Boilermaker" categories were not broken out for the EDD Stockton MSA labor force projections Construction and Extractions Occupation data sets.
[2] Includes both "Construction" and "Laborers" estimated number of total construction workers by craft needed during the peak month (month 24) as presented in the AFC (HEI 2008c, p. 2-79)
N/A – Not enough information is available to determine "Teamsters" and "Off Plot Construction Craft" labor classifications as presented in the AFC (HEI 2008c, p. 2-79).

As shown in Table 4, the Bakersfield MSA construction workforce would provide adequate labor for construction of the proposed HECA. As such, staff concludes the proposed project would not induce substantial growth or concentration of population in the project area and construction of the HECA project would not encourage people to permanently relocate to the area. On p. 5.8-23 of the AFC, the applicant states that 81 workers will relocate to Kern County, resulting in a population increase of 253 people in communities within the proposed HECA project area (HEI 2008c). However, staff's independent analysis (based on information contained in **Table 4**) shows that there is more than adequate local workforce for peak month project construction. In the event a small number of the construction workforce is drawn from outside the Bakersfield MSA, due to the temporary nature of construction labor, staff concludes it is unlikely these workers would permanently relocate to the area as a direct result of temporary employment resulting from HECA construction activities.

The proposed HECA project is expected to require a total of 100 permanent full-time employees (HEI 2008c, p. 5.8-21). **SOCIOECONOMICS Table 5** shows Year 2006-2016 occupational employment projections for the Bakersfield MSA (Kern County) by operational labor skill as compared to the estimated number of total operational workers needed as presented in the AFC (HEI 2008c, p. 5.8-21).

SOCIOECONOMICS Table 5
Total Labor by Skill in Bakersfield MSA (2006 and 2016 Estimate) and HECA Required Operation

Trade	Bakersfield MSA 2006	Bakersfield MSA 2016	Total # of Workers for Project Operation
Plant and System Operators	1,460	1,600	--
Power Plant Operators	190	220	--
Total	*1,650*	*1,820*	*100*
Source: EDD 2009.			

As shown in **Table 5**, the Bakersfield MSA power plant related operational workforce would provide adequate labor for operation of the proposed HECA. As such, staff concludes the proposed project would not induce substantial growth or concentration of population in the project area and operation of the HECA project would not encourage people to permanently relocate to the area. On p. 5.8-23 of the AFC, the applicant states that 20 workers will relocate to Kern County, resulting in a population increase of 63 people in communities within the proposed HECA project area (HEI 2008c). However, staff's independent analysis (based on **Table 5**) shows that the Bakersfield MSA provides adequate local workforce for project operation. Therefore, due to this labor force located within the Bakersfield MSA, staff concludes that the new operational employees required for the HECA project would be found locally.

Displace Existing Housing

The proposed HECA project site is located on land currently used for agricultural use, with the nearest housing unit being located approximately 1,400 feet to the east of the HECA project site (HEI 2008c, p. 5.4-5). No housing structures exist on the property and no lands used for proposed project use would interfere with lands zoned for residential use. As such, no housing would be displaced. With regard to housing displacement associated with required transmission line infrastructure associated with the proposed project, approximately six single-family dwellings are located within 500 feet of Transmission Alternative 1, whereas no single-family dwellings are located within 0.25-mile from Transmission Alternative 2 (HEI 2008c, p. 5.4-8). While housing is located adjacent to proposed transmission infrastructure, no housing would be displaced from required transmission line connections. Therefore, the HECA project would not displace existing housing or necessitate construction of replacement housing elsewhere.

Displace Substantial Numbers of People

As discussed above, the proposed HECA project site is on land currently used for agricultural use, with the nearest housing unit being located approximately 1,400 feet to the east of the HECA project site (HEI 2008c, p. 5.4-5). Furthermore, no housing would be displaced from required transmission line infrastructure. As such, no persons would be displaced.

Result in Substantial Physical Impacts to Government Facilities

As discussed under the subject headings below, the proposed HECA project would not cause significant impacts to service ratios, response times, or other performance objectives relating to emergency medical services, law enforcement, or schools. Fire protection is analyzed in the **Worker Safety and Fire Protection** section of this document.

Emergency Medical Services

The nearest hospitals to the HECA project site are Mercy Southwest and HealthSouth Bakersfield, located approximately 21 miles northeast and 25 miles east of the site, respectively (HEI 2008c, p. 5.8-15). In the event a worker or employee requires emergency medical care at the HECA site, Mercy Southwest Hospital is a primary medical facility and has an emergency room, and indicates that the emergency department team and facility is fully equipped to handle workplace accidents (Mercy Southwest 2009). Any major trauma would likely be sent to Bakersfield General Hospital in Bakersfield, due to the size of this hospital and proximity (approximately 32-miles from the proposed HECA site). Bakersfield General Hospital does have a heliport to transport patients to this facility (Thomas Guide 2010).

During HECA construction, the applicant's engineering, procurement, and construction contractor will be responsible for providing site security, health and safety training, and site first aid services (URS 2010b). First-aid kits would be located around the project site, and will be maintained regularly (URS 2010b). At least one person trained in first aid would be part of the construction staff upon mobilization, and additional personnel with appropriate skills for site first aid and medical support (nurse and/or medical practitioner) would be added as the construction crew size increases (URS 2010b). All foremen and supervisors will be required to have first-aid training (URS 2010b). Prior to commencement of construction activities, the project applicant, and the assigned contractors and operations and management staff, will meet and develop a site-specific Construction Emergency Response Program (URS 2010b). The development, coordination, and review of this plan is required by Condition of Certification **WORKER SAFETY-1**, as discussed in the **Worker Safety and Fire Protection** section of this document. Once operational, emergency preparedness includes the development of a Communications and Response Plan for emergency situations during HECA project operation, including identification of area hospitals and clinics and coordination with local emergency response organizations in Bakersfield and elsewhere in Kern County (URS 2010b). The development, coordination, and review of this plan is required by Condition of Certification **WORKER SAFETY-2**, as discussed in the **Worker Safety and Fire Protection** section of this document.

The inclusion of Conditions of Certification **WORKER SAFETY-1** and **WORKER SAFETY-2** in combination with the available hospital facilities serving the HECA site (as described above), staff concludes the proposed HECA project would not significantly impact the existing service levels or response times of the hospitals serving the study area. Furthermore, as discussed above, staff concludes that the required construction and operational workforce required for the HECA project would be found locally.

Therefore, construction and operation of the HECA project would have no direct or indirect impact on population growth in the area that would require the need for new or expanded emergency medical facilities or staff levels.

Law Enforcement

The Kern County Sheriff's Office (KCSO) provides law enforcement services to the unincorporated portion of Kern County, which includes the proposed HECA project site. The department has approximately 1,330 sworn and civilian employees and 572 authorized deputy sheriff positions deployed in patrol, substations, detectives, courts services, and special investigations units (KCSO 2009a). The Taft Substation of the KCSO provides law enforcement services to the proposed HECA site. The Taft Substation is located at 315 Lincoln Street in Taft, approximately 16 miles southwest of the proposed project site. KSCO staff at this substation includes one sergeant, one senior deputy, nine deputies, one clerk, nine deputies, two detectives, a school resource deputy, and a bailiff assigned (KCSO 2009b).

As discussed above, staff concludes that the required construction and operational workforce required for the HECA project would be found locally. Therefore, construction and operation of the HECA project would have no direct or indirect impact on population growth in the area that would require the need for new or expanded law enforcement facilities or staff levels. KCSO could not estimate an expected response time to the HECA site, but KCSO indicated it has staff and equipment to adequately serve the proposed project (HEI 2008c, p. 5.8-25). Furthermore, the proposed project will include a security system during both construction and operational phases (HEI 2008c, p. 5.8-25). Therefore, construction and operation of the HECA project would not require the need for new or expanded law enforcement facilities or staff levels.

Education

The proposed project site is located within the boundaries of the Elk Hills Elementary School District and the Taft Union High School District. The Elk Hills Elementary School District operates one school (Elk Hills Elementary), at which 73 students were enrolled during the 2006-2007 school year (HEI 2008c, p. 5.8-16). Taft Union High School District operates two high schools and one continuation school, with a total enrollment of 1,100 students during the 2006-2007 school year (HEI 2008c, p. 5.8-16). Elk Hills Elementary School District does not publish enrollment projections; however, the District does not anticipate exceeding capacity within the next 10 years (HEI 2008c, p. 5.8-16). In addition, while the Taft Union High School District does not publish enrollment projections and is currently unable to provide an enrollment capacity; the school district does not believe that student enrollment within the next 10 years will overburden the district (HEI 2008c, p. 5.8-16).

As discussed above, staff concludes that the required construction and operational workforce required for the HECA project would be found locally. Therefore, construction and operation of the HECA project would have no direct or indirect impact on population growth in the area that would require the need for new or expanded school facilities or staff levels at either the Elk Hills Elementary School District or the Taft Union High School District.

Education Code section 17620 authorizes a school district to levy a fee against any construction within a district. However, as indicated in the AFC, telephone conversations between the HECA applicant and both the Elk Hills Elementary School District and Taft Union High School District determined that both school districts do not impose developer school impact fees and would not impose school impact fees on the proposed HECA project (HEI 2008c, p. 5.8-26). Therefore, as no school impact fee is imposed by the applicable school districts, the HECA project would be in compliance with Education Code section 17620 (as described in **SOCIOECONOMICS Table 1)**.

Increase the Use of Existing Recreation Facilities

Within a one-mile radius of the proposed HECA project site, approximately 275 acres of park, open space, and recreational land is available (HEI 2008c, p. 5.4-6). The demand for new or expanded park and recreational facilities is generally associated with an increase in housing or population. As discussed above, staff concludes that the required construction and operational workforce required for the HECA project would be found locally. Therefore, construction and operation of the HECA project would have no direct or indirect impact on population growth in the area that would require the need for new or expanded recreational facilities or staff levels serving the proposed project area.

CUMULATIVE IMPACTS AND MITIGATION

A project may result in significant adverse cumulative impacts when its effects are “cumulatively considerable.” Cumulatively considerable means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, or the effects of probable future projects (Title 14, California Code of Regulations, section 15130). Cumulative socioeconomics impacts could occur when more than one project has an overlapping construction schedule that creates a demand for workers that cannot be met by the local labor force, resulting in an influx of non-local workers and their dependents. Operational cumulative socioeconomic impacts could occur when the development of multiple projects significantly impacts the population of an area thus resulting in a housing shortage, change in local employment conditions, and an increased demand on public services.

A total of 7 projects are located within a six-mile radius of the proposed HECA project site that could have an adverse cumulative socioeconomic effect (HEI 2008c, p. 5.8-30). Project types include dairy farm development, industrial use, commercial use, and a proposed hotel within the community of Buttonwillow. No residential projects such as new residences, additions and remodels to existing residences, or mobile home parks were identified to occur within a six-mile radius of the proposed HECA project site (HEI 2008c, p. 5.8-30). **SOCIOECONOMICS Tables 4 and 5** present the most recently published data (Year 2006-2016 projections) on labor force characteristics for the Bakersfield MSA, which includes Kern County. As discussed above, staff concludes that the required construction and operational workforce of the proposed HECA project would be found locally, with no population inmigration that would increase the local population. Therefore, because the proposed HECA project would be adequately served by the local labor force, it would not contribute to cumulative increases in population that would generate an increase in demand for local housing and public services.

While continued development of the area would likely result in an increase in population and require the need for new housing and expanded public service facilities, operation of the proposed HECA project would not contribute to these impacts. Despite the potential for construction schedule overlaps with known projects within the proposed HECA project area, no adverse cumulative socioeconomic effects are anticipated from either the construction or operation of the proposed HECA project. In addition, both the short-term construction-related and long-term operation-related spending activities of the HECA project are expected to have cumulative economic benefits for the study area (refer to **SOCIOECONOMICS Table 6**). The cumulative benefits would increase when revenues accrued as a result of the proposed HECA project are combined with spending, and any local revenues accrued as a result of current and future reasonably foreseeable cumulative development projects.

NOTEWORTHY PUBLIC BENEFITS

Important public benefits include both the short-term construction and long-term operational related increases in local expenditures and payrolls, as well as sales tax revenues. Estimated gross public benefits from the HECA project include increases in sales taxes and employment payrolls. **SOCIOECONOMICS Table 6** provides a summary of economic benefits of the proposed HECA project.

SOCIOECONOMICS Table 6
HECA Economic Benefits (2008 dollars)

Fiscal Benefits	
Estimated annual property taxes	$15,970
State and local sales taxes: Construction	$5.4 million
State and local sales taxes: Operation	$942,500
School Impact Fee	$0
Total capital costs	$1.6 billion
Construction payroll	$350 million
Construction materials and supplies	$1.25 billion
Annual Operations and Maintenance	$80 million
Operations and maintenance supplies	$19.5 million
Direct, Indirect, and Induced Benefits	
Estimated Direct Employment	
Construction Employment	1,482 jobs (maximum)
Construction Payroll	$350 million
Operational Employment	100 jobs (maximum)
Operational Payroll	$80 million
Estimated Indirect and Induced Effects	
Construction Jobs	4,000 jobs
Construction Labor Income	$209 million
Total Construction Economic Output	$638 million
Operational Jobs	55 jobs
Operational Labor Income	$2 million
Total Operational Economic Output	$7 million
Source: HEI 2008c.	

PROPOSED CONDITIONS OF CERTIFICATION

No conditions of certification are required for socioeconomic resources because no significant adverse socioeconomics impacts would occur as a result of construction and operation of the proposed HECA project.

CONCLUSIONS

No significant adverse socioeconomics impacts would occur as result of the construction or operation of the proposed HECA project. Staff believes the HECA would not cause a significant adverse direct, indirect, or cumulative impact on population, employment, housing, public finance, local economies, or public services. In addition, because there would be no adverse project-related socioeconomic impacts, minority and low-income populations would not be disproportionately impacted. The proposed HECA project would benefit the study area in terms of an increase in local expenditures and payrolls during construction and operation of the facility. These activities would have a positive effect on the local and regional economy.

REFERENCES

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HEI 2008c - Hydrogen Energy International, LLC /J. Briggs (tn 51735). Revised Application for Certification, dated 05/28/09. Submitted to CEC/Docket Unit on 05/28/09.

KCSO 2009a - Kern County Sheriff’s Office information. [online] http://www.kernsheriff.com/Pages/default.aspx

KCSO 2009b - Kern County Sheriff’s Office Taft Substation information. [online] http://www.kernsheriff.com/FieldOps/Substations/Taft/Pages/default.aspx

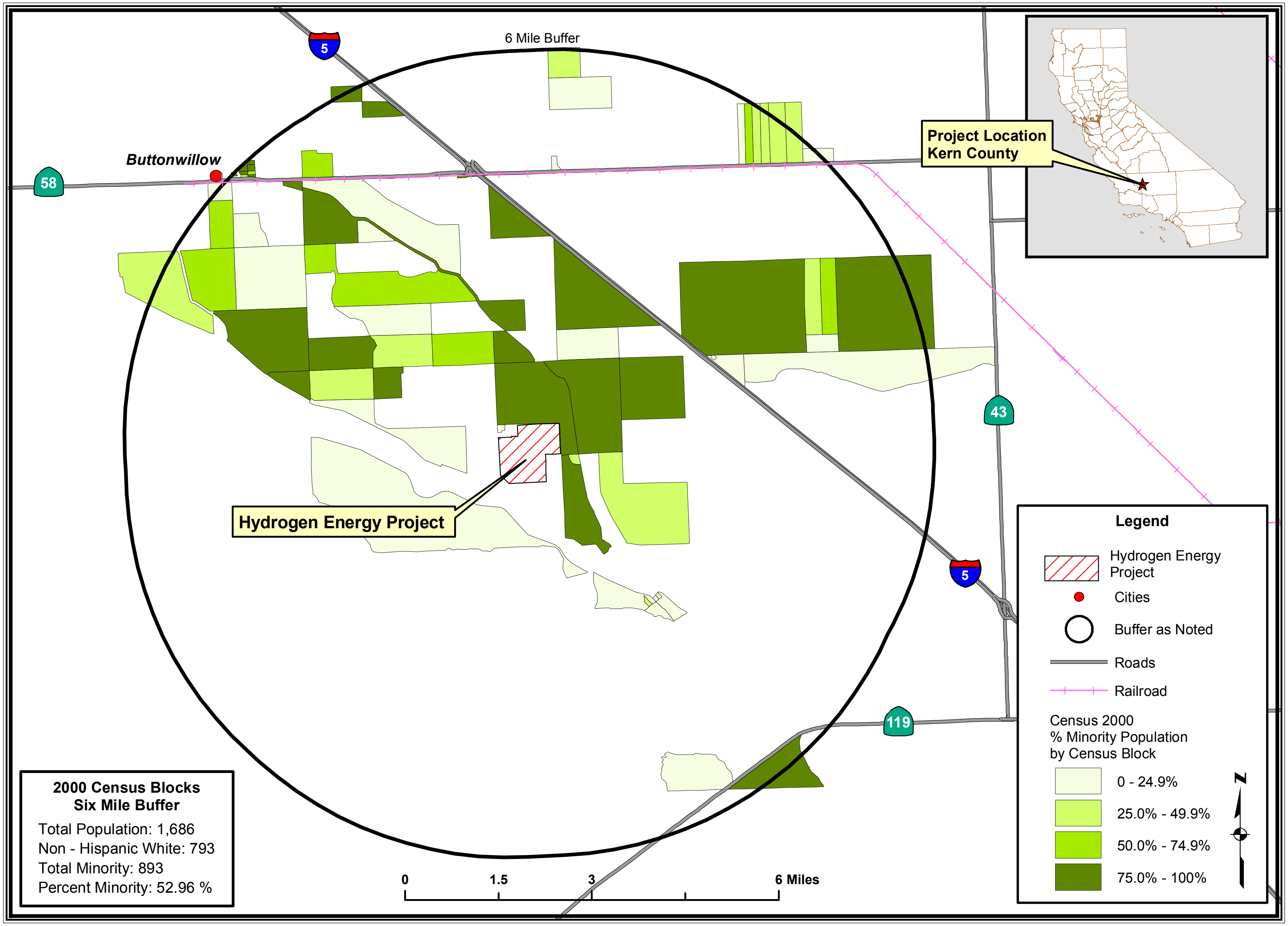
Mercy Southwest 2009 - Mercy Southwest Hospital 24-Hour Emergency Services information. [online] http://www.mercybakersfield.org/Medical_Services/MEBV2_M120680

Thomas Guide 2010 - Thomas Brothers Map Guide Kern County Map.

URS 2010b - URS/D. Shileikis (tn 55121). Applicant's Response to Energy Commission Data Requests Set Two, dated 2/1/10. Submitted to CEC/Docket Unit on 2/2/10.

SOCIOECONOMICS - FIGURE 1

Hydrogen Energy California - Census 2000 Minority Population by Census Block - Six Mile Buffer



SOCIOECONOMICS

CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION

SOURCE: California Energy Commission Statewide Power Plant Maps 2010 - Census 2000 PL 94-171 Data - Matrix PL2

TRAFFIC AND TRANSPORTATION

Scott Debauche

SUMMARY OF CONCLUSIONS

California Energy Commission (Energy Commission) staff has analyzed the traffic-related information provided in the Application for Certification (AFC) and other sources to determine the potential for the approximately 250 MW Integrated Gasification Combined Cycle power generating facility, referred to as the Hydrogen Energy California project (HECA or proposed project), to have adverse traffic- and transportation-related impacts. Staff has also assessed the availability of mitigation measures that could reduce or eliminate the significance of these impacts.

Construction of the proposed HECA project will add traffic to local roadways during the construction period. This increase in traffic could impact existing traffic load and capacity of the street system. In addition, construction activities could result in impacts to aviation safety, damage to public roadways, and introduce oversize and overweight vehicles on the local street system. Once the HECA project is operational, traffic volumes generated from operations would not significantly impact the local transportation network; however, intersection improvements associated with project construction traffic mitigation is required to result in less than significant operational traffic impacts.

If the Energy Commission elects to grant certification for this project, staff is proposing six conditions of certification. These conditions of certification are recommended to prevent significant adverse traffic and transportation-related impacts from HECA construction and operation and to ensure that the project would comply with all applicable laws, ordinances, regulations, and standards (LORS) pertaining to traffic and transportation. Energy Commission staff concludes that with implementation of proposed Conditions of Certification TRANS-1 through TRANS-9, the proposed HECA project would not generate a significant impact under the California Environmental Quality Act (CEQA) guidelines with respect to CEQA Appendix G issues, “Transportation and Traffic.”

INTRODUCTION

In the **Traffic and Transportation** section, staff addresses the extent to which the proposed HECA project may affect the traffic and transportation system within the vicinity of the project site. This analysis focuses on whether construction and operation of HECA would cause traffic and transportation impact(s) under CEQA and whether the project complies with the applicable LORS.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Traffic and Transportation Table 1 provides a general description of adopted federal, state, and local LORS pertaining to traffic and transportation relevant to the proposed project.

Traffic and Transportation Table 1
Laws, Ordinances, Regulations, and Standards

Applicable Law	Description
Federal	
Aeronautics and Space Title 14 Code of Federal Regulations (CFR), part 77 Objects Affecting Navigable Airspace (14 CFR 77)	Establishes standards for determining physical obstructions to navigable airspace; sets noticing and hearing requirements; and provides for aeronautical studies to determine the effect of physical obstructions on the safe and efficient use of airspace.
49 CFR, Subtitle B	Includes procedures and regulations pertaining to interstate and intrastate transport (including hazardous materials program procedures) and provides safety measures for motor carriers and motor vehicles that operate on public highways.
State	
California Vehicle Code (CVC), division 2, chapter 2.5; div. 6, chap. 7; div. 13, chap. 5; div. 14.1, chap. 1 & 2; div. 14.8; div. 15	Includes regulations pertaining to licensing, size, weight, and load of vehicles operated on highways; safe operation of vehicles; and the transportation of hazardous materials.
California Streets and Highway Code, division 1 & 2, chapter 3 & chapter 5.5	Includes regulations for the care and protection of state and county highways and provisions for the issuance of written permits.
California Street and Highway Code §§117, 660-711	Requires permits from California Department of Transportation (Caltrans) for any roadway encroachment during truck transportation and delivery.
California Street and Highway Code §§660-711	Requires permits for any load that exceeds Caltrans weight, length, or width standards for public roadways.
Local	
Kern County Airport Land Use Compatibility Plan (ALUCP)	Requires local agencies to ensure compatible land uses in the vicinity of existing or proposed airports; to coordinate planning at state, regional, and local levels; to prepare and adopt an airport land use plan; to review plans, regulations, or locations of agencies and airport operators; and to review and make recommendations regarding the land uses, building heights, and other issues relating to air navigation safety and promotion of air commerce.
Kern County General Plan Circulation Element	• Chapter 2 (Circulation Element), Goal 5, specifies that all county roadways shall operate at a Level of Service D or better; • Circulation Element Subsection 2.3.3 (Highway Plan), Goal 5, specifies that all county highways shall operate at a Level of Service D or better; and • Circulation Element, Policy 4, specifies that as a condition of private development approval, developers shall build roads needed to access the existing road network. Developers shall build these roads to County standards unless improvements along state routes are necessary then roads shall be built to California Department of Transportation standards. Developers shall locate these roads (width to be determined by the Circulation Plan) along centerlines shown on the circulation diagram map unless otherwise authorized by an approved Specific Plan Line. Developers may build local roads along lines other than those on the circulation diagram map. Developers would negotiate necessary easements to allow this requirement.
Kern County Regional Transportation Plan	Chapter 4 (Strategic Investments) of the Regional Transportation Plan (RTP) includes a listing of State highways and principal arterials within Kern County designated as part of the Congestion Management System, including level of service standards (Level of Service E or better) for these designated RTP roadways.

SETTING

The 473-acre proposed HECA project site is comprised of portions of two parcels currently used for farming purposes. In addition, the proposed project applicant is also purchasing four additional parcels adjacent to the project site totaling 628 acres for the purposes of public access control and future land uses. The HECA site is bounded by Adohr Road on the north, Tupman Road to the east, an irrigation canal to the south, and Dairy Road to the west. Primary access to the site is from Adohr Road (HEI 2008c, p. 5.4-4). Stockdale Highway and Interstate 5 are located approximately 1 mile to the north and 3 miles to the east, respectively. The Elk Hills-Buttonwillow Airport, which is a public airport primarily used for general aviation, is located approximately 5 miles northwest of the proposed project site. Elk Hills Oil Field is located approximately 1 mile south of the proposed HECA site. **Traffic and Transportation Figures 1-1** through **1-4** display the regional and local roadway system.

CRITICAL ROADS AND FREEWAYS

The transportation network within the proposed HECA project area is composed of a mix of interstate, county highways, and local roadways. The following describes the main regional and local roadways that would be used for HECA construction and operational related traffic accessing the proposed project site.

Existing Regional and Local Transportation Facilities

Interstate 5 (I-5)

I-5, located approximately 4 miles east of the HECA site, is a major north-south regional transportation route through Kern County. Near the HECA site, I-5 provides two mainline lanes in each direction with wide shoulders and a center median, providing separate acceleration/deceleration lanes at the interchange of I-5/State Route 119, I-5/Stockdale Highway, and I-5/State Route 58 (HEI 2008c, p. 5.10-5). The speed limit of I-5 in the vicinity of the proposed HECA site is posted at 70 miles per hour (mph) for cars and 55 mph for trucks (HEI 2008c, p. 5.10-5). The Annual Average Daily Traffic (AADT) on the segment of I-5 within the proposed project area is 32,000 vehicles per day, with truck traffic accounting for 26% of this volume (HEI 2008c, p. 5.10-5).

State Route 119 (SR 119)

SR 119 is an east-west state highway located approximately 7 miles south of the HECA site. Near the HECA site, SR 119 that has a two-lane (one lane in each direction) cross section with an 8- to 12-foot shoulder on both sides with a posted speed limit of 55 mph (HEI 2008c, p. 5.10-5). The ADT on the highway just west of I-5 southbound ramps is 12,300 vehicles per day, with truck traffic accounting for 26% of this volume (HEI 2008c, p. 5.10-5).

State Route 58 (SR 58)

SR 58, located approximately 4 miles north of the proposed HECA site, is an east-west state highway consisting of a two-lane conventional state highway with 4- to 8-foot shoulders and a posted speed limit of 55 mph in vicinity near the HECA site (HEI 2008c, p. 5.10-5). The I-5 southbound ramp/SR 58 interchange is currently signalized (HEI

2008c, p. 5.10-5). The ADT on the segment of SR 58 to the north of the proposed project site is 2,200 vehicles per day, with truck traffic accounting for 32% of this volume (HEI 2008c, p. 5.10-6). SR 58 is designated as a state truck route (HEI 2008c, p. 5.10-5).

Stockdale Highway

Stockdale Highway is an east-west highway located one mile north of the HECA site. It starts near Wasco Way on the west and continues to the east through metropolitan Bakersfield, with an unsignalized freeway interchange provides connection to I-5. The segment of Stockdale Highway in the vicinity of the proposed HECA project has two through lanes (one lane in each direction) with no shoulders and a posted speed limit of 55 mph (HEI 2008c, p. 5.10-6).

Adohr Road

Adohr Road is an east-west roadway containing two-lanes and is classified as Major (Arterial) Highway by the Kern County General Plan Circulation Element and would provide main access to the proposed HECA site (HEI 2008c, p. 5.10-7). This roadway starts at Freeborn Road on the west and ends at Tupman Road on the east and is relatively straight with flat terrain in the vicinity of the proposed HECA site (HEI 2008c, p. 5.10-7).

Dairy Road

Dairy Road is a north-south local roadway containing two-lanes starting at Adohr Road on the south and ends at Stockdale Highway on the north. The intersection of Stockdale Highway and Dairy Road is controlled by a stop sign on Dairy Road (HEI 2008c, p. 5.10-6). The roadway segment is relatively straight and the terrain is flat in the vicinity of the proposed HECA site (HEI 2008c, p. 5.10-6).

Morris Road

Morris Road is a north-south local roadway containing two-lanes starting at Station Road on the south and ends at Stockdale Highway on the north. The intersection of Stockdale Highway and Morris Road is controlled by a stop sign on Morris Road (HEI 2008c, p. 5.10-6). The roadway segment is relatively straight and the terrain is flat in the vicinity of the HECA site (HEI 2008c, p. 5.10-6).

Station Road

Station Road is an east-west local roadway containing two-lanes starting at Tupman Road on the west and ends at Morris Road on the east. The intersection of Tupman Road and Station Road is controlled by a stop sign on Station Road (HEI 2008c, p. 5.10-6). The roadway segment is relatively straight and the terrain is flat in the vicinity of the HECA site (HEI 2008c, p. 5.10-6).

Tupman Road

Tupman Road is a north-south two-lane primary road adjacent to the eastern boundary of the HECA site, classified as a collector road by the Kern County General Plan Circulation Element (HEI 2008c, p. 5.10-6). The intersection of Tupman Road and SR 119 is unsignalized with stop signs on Tupman Road (HEI 2008c, p. 5.10-6). Heading north from SR 119, the terrain is relatively flat to moderately rolling grade, with some segments having limited horizontal sight visibility to opposing traffic (HEI 2008c, p. 5.10-6). The posted speed limit is 55 mph in the vicinity of the proposed HECA site (HEI 2008c, p. 5.10-6).

Current Roadway Conditions

Level of Service (LOS)

LOS is a qualitative measure describing operational conditions within a traffic stream. It is used to describe and quantify the congestion level on a particular roadway or intersection and generally describes these conditions in terms of such factors as speed or vehicle movement. Traffic and Transportation Table 2 summarizes intersection LOS for associated vehicle delay.

Traffic and Transportation Table 2
Level of Service Criteria for Roadways and Intersections

Level of Service	Description	Signalized Intersection Delay (seconds per vehicle)	Stop-Controlled Intersection Delay (seconds per vehicle)
A	Free flow; insignificant delays	<10.0	<10.0
B	Stable operation; minimal delays	10.1 – 20.0	10.1 – 15.0
C	Stable operation; acceptable delays	20.1 – 35.0	15.1 – 25.0
D	Approaching unstable flow; queues develop rapidly but no excessive delays	35.1 – 55.0	25.1 – 35.0
E	Unstable operation; significant delays	55.1 – 80.0	35.1 – 50.0
F	Forced flow; jammed conditions	>80.0	>50.0

Source: HEI 2008c, p. 5.10-8

Current Intersection Conditions — LOS

To quantify the existing baseline traffic conditions, the study area roadways and intersections were analyzed in the AFC to determine their operating conditions. Based on existing traffic volumes, turning movement counts, intersection control device, and the existing number of lanes, the LOS has been determined for each intersection.

Traffic and Transportation Table 3 summarizes the results of the existing morning and afternoon peak-hour LOS analysis for intersections located within the proposed HECA project area that could be impacted by proposed project construction and operational related traffic. As shown in **Table 3**, all study area intersections operate at LOS C or better.

Traffic and Transportation Table 3
Existing (2009) Intersection Level of Service Summary

Intersection	Control	AM Peak Hour		PM Peak Hour	
		Delay (sec)	LOS	Delay (sec)	LOS
I-5 NB Ramp/Stockdale Hwy.	Unsignalized	1.2	A	1.9	A
I-5 SB Ramp/Stockdale Hwy.	Unsignalized	3.4	A	7.0	A
I-5 NB Ramp/SR 119	Unsignalized	1.0	A	0.6	A

I-5 SB Ramp/SR 119	Unsignalized	0.4	A	0.9	A
SR 119/SR 43	Signalized	27.0	C	33.9	C
SR 43/Stockdale Hwy.	Unsignalized	11.2	B	16.3	C
Stockdale Hwy./Morris Rd.	Unsignalized	1.7	A	2.0	A
SR 119/Tupman Rd.	Unsignalized	0.8	A	3.4	A
Tupman Rd./Grace Ave.	Unsignalized	7.0	A	7.1	A
Tupman Rd./Station Rd.	Unsignalized	3.8	A	1.1	A
Dairy Rd./Stockdale Hwy.	Unsignalized	1.5	A	0.6	A
Dairy Rd./Adohr Rd.	Unsignalized	5.7	A	1.9	A

Source: HEI 2008c, p. 5.10-10
Notes: NB – Northbound; SB – Southbound; Sec – Seconds

RAILWAYS

The nearest rail lines serving the proposed HECA site are a Union Pacific Railroad (UPRR) and Burlington Northern Santa Fe (BNSE) rail lines, both located approximately 6 miles east of the site (HEI 2008c, p. 5.10-6). In addition to these lines, San Joaquin Valley Railroad provides local train connection to areas west of Bakersfield and The AMTRAK California San Joaquin Route connects downtown Bakersfield to Sacramento and the Bay Area (HEI 2008c, p. 5.10-6).

BUS TRANSPORTATION

The Kern County Roads Department Transit Division plans, coordinates, and administers the public transit system, Kern Regional Transit (KRT), within the County's unincorporated areas by providing a combination of demand-response, fixed-route, and inter-city transit services. (Kern County 2009b). The nearest KRT line to the proposed HECA project site is the Buttonwillow Route located approximately 3.9 miles northwest of the project site (Kern County 2009b).

BICYCLES AND PEDESTRIANS

The 2001 Kern County Bicycle Plan describes the existing and planned bicycle facilities for the metropolitan Bakersfield area, Wasco, Taft, and other cities and communities in Kern County (Kern County 2001). Based on the 2001 Kern County Bicycle Plan and visual inspections of the proposed HECA site, no existing or planned bicycle facilities are within the immediate vicinity of the project site (Kern County 2001).

AIRPORTS

The proposed HECA project site is approximately 4.6 miles southeast of the Elk Hills-Buttonwillow Airport. Elk Hills-Buttonwillow Airport is a general aviation airport with one runway, runway 11/29 oriented northwest/southeast (AirNav 2009). Elk Hills-Buttonwillow Airport is owned by the Kern County Department of Airports and serves agricultural and other general aviation activities (AirNav 2009). For the one-year time frame ending March 13, 2009 (most recently published statistic), the Elk Hills-Buttonwillow Airport handled an average of 23 aircraft per week, of which 100% was transient general aviation (AirNav 2009). Elk Hills-Buttonwillow Airport runway 11/29 observes a recommended right turn traffic pattern when departing Runway 11 (to the northwest) and a recommended left turn traffic pattern when departing Runway 29 (to the southeast), directing aircraft toward the proposed HECA project site (AirNav 2009).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Significance criteria are based on the following:

1. California Environmental Quality Act (CEQA) Guidelines, including the CEQA Checklist found in Appendix G to the CEQA Guidelines, Section XVI. Transportation/Traffic.
2. Performance standards and thresholds established by state and local agencies

According to the Amendments of the CEQA Guidelines, effective March 18, 2010, a project may have a significant impact on the transportation system if it would:

- Cause an increase in traffic which is substantial in relation to the existing traffic load and capacity of the street system (i.e., result in substantial increase in either the number of vehicle trips, the volume to capacity ratio on roads, or congestion at intersection);
- Conflict with an applicable plan, ordinance, or policy establishing measures of effectiveness for the performance of the circulation system, taking into account all modes and transportation, including mass transit and nonmotorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths;
- Conflict with an applicable congestion management program, including, but not limited to, level of service standards (LOS) and travel demand measures or other standards established by the county congestion management agency for designated roads or highways;
- Result in a change in air traffic patterns, including either an increase in traffic levels of a change in location that results in substantial safety risks;
- Substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment). CEQA compliance to this guideline is determined by the extent, if any, that the project would substantially increase hazards due to a design feature. Result in inadequate emergency access;
- Result in inadequate emergency access;
- Result in inadequate parking capacity; or
- Conflict with adopted policies, plans, or programs supporting alternative transportation (e.g., bus turnouts, bicycle racks).

DIRECT/INDIRECT IMPACTS AND MITIGATION

Intersection Levels of Service

Construction Impacts and Mitigation

As stated in AFC Section 2.0 (Project Description), the applicant expects that construction of the proposed HECA project would last approximately three years, starting in 2011 and ending in 2014. There would be an average of approximately 740 daily construction workers, with a peak daily workforce of 1,482 during month 24 of construction (HEI 2008c, p. 2-79). Month 24 would be the peak construction period when the highest total number of daily trips is anticipated. Therefore, estimated daily construction trips during Month 24 were used to determine potential impacts, as this would represent the worst-case construction traffic scenario. The traffic analysis assumed that some workers would carpool and assumed one-third of the worker vehicles would arrive during the morning peak hour of 7:00 a.m. to 9:00 a.m., and all would depart during the evening peak hour of 4:00 P.M. to 6:00 P.M. (HEI 2008c, p. 5.10-11).

For purposes of this analysis, both the construction vehicle delivery and worker trips were converted to passenger car equivalent (PCE) trips, consistent with Caltrans *Highway Capacity Manual* guidelines. A detailed breakdown of this determination and methodology is provided in the AFC (HEI 2008c, pp. 5.10-11 and 12). Traffic and Transportation Table 4 lists the estimate of total construction vehicle trip for the proposed HECA project in PCE, identifying which of those would be generated during both the A.M. and P.M. peak hour periods.

Traffic and Transportation Table 4
Estimated Average and Peak Hour Trip Generation – Peak Construction Period

	Total Daily Trips	A.M. Peak Hour			P.M. Peak Hour		
		In	Out	Total	In	Out	Total
Total Construction Traffic in PCE	**3,568**[1]	**508**	**123**	**631**	**123**	**1,277**	**1,400**

Source: HEI 2008c, p.5.10-12

[1]Total Average Daily Trips includes off-peak hour construction related trips

Based on the construction vehicle trip calculations presented in Traffic and Transportation Table 4, an analysis was conducted in the AFC to determine the impacts of these construction vehicle trips on current study area intersections LOS. Traffic and Transportation Table 5 identifies the current (2009) and future (2014) LOS anticipated with and without the proposed project construction vehicle traffic for critical intersections in the vicinity of the project. As described in Traffic and Transportation Table 1**, Kern County does** not have any LORS specifying acceptable LOS thresholds for intersections (General Plan Circulation Element LOS thresholds are specific to roadway segments). However, in maintaining consistency with the Kern County General Plan Circulation Element, staff utilized a LOS D threshold for determining intersection LOS impacts.

As shown in Traffic and Transportation Table 5, with the addition of the HECA project's peak construction traffic, all study area intersections will continue to operate at an acceptable LOS during the A.M. peak hour as compared to the future Year 2014 without project conditions. During the P.M. peak hour, the HECA project's peak construction traffic will temporarily impact both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections, which are projected to degrade to LOS F. In addition to direct construction related trips, interconnecting the HECA project into the Pacific Gas and Electric (PG&E) system will require the construction of approximately 8 miles of transmission line. Intersections and roadway segments along the transmission line routes may be temporarily affected during construction. However, traffic impacts at roadways during utility infrastructure stringing activities will be site-specific and temporary in duration.

To minimize impacts from construction related trips, staff is proposing Condition of Certification **TRANS-1,** which would require the applicant to prepare a Construction Traffic Control Plan prior to construction in order to reduce the significance of construction traffic. Even with the implementation of Condition of Certification **TRANS-1,** construction related traffic impacts would remain significant at both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections due to construction related traffic temporarily reducing these intersections from LOS A to LOS F conditions during the P.M. peak hour. As indicated in the AFC, the applicant is proposing improvements to these intersections to reduce LOS impacts (HEI 2008c, p. 5.10-23). To ensure these improvements are made, Condition of Certification **TRANS-2** is proposed and will require physical improvements at the SR 43/Stockdale Highway, SR 119/Tupman Road, Dairy Road/Stockdale Highway, and Dairy Road/Adohr Road intersections to reduce impacts from construction related trips at both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections to a less than significant level.

It should be noted that coordination with Kern County has indicated that the physical intersection improvements associated with Condition of Certification **TRANS-2** would not require any construction outside of the existing right-of-way (ROW) at the Dairy Road/Stockdale Highway and Dairy Road/Adohr Road intersections (CEC 2010). The existing width of Dairy Road is 24-feet, with the proposed improvements associated with Condition of Certification **TRANS-2** requiring an additional 12-feet (CEC 2010). As the existing Dairy Road ROW is 60-feet, no construction would occur outside of the existing ROW (CEC 2010). Furthermore, Condition of Certification **TRANS-2** requires the project owner and/or construction contractor to coordinate with and have approval from Kern County prior to making the intersection improvements specified in **TRANS-2**.

Traffic and Transportation Table 5
Current and Anticipated Year 2014 With and Without Project Intersection Levels of Service - Construction

Intersection[1]	AM						PM					
	Current (2009)		2014 Without Project		2014 With Project		Current (2009)		2014 Without Project		2014 With Project	
	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS
I-5 NB Ramp/Stockdale Hwy.	1.2	A	1.2	A	3.4	A	1.9	A	2.0	A	19.2	C
I-5 SB Ramp/Stockdale Hwy.	3.4	A	3.3	A	3.2	A	7.0	A	7.3	A	33.7	D
I-5 NB Ramp/SR 119	1.0	A	1.0	A	1.7	A	0.6	A	0.6	A	0.7	A
I-5 SB Ramp/SR 119	0.4	A	0.3	A	0.4	A	0.9	A	1.0	A	2.3	A
SR 119/SR 43	27.0	C	27.3	C	28.3	C	33.9	C	33.3	C	35.1	D
SR 43/Stockdale Hwy.	11.2	B	12.2	B	16.9	B	16.3	C	20.8	C	147.3	F*
Stockdale Hwy./Morris Rd.	1.7	A	1.7	A	0.4	A	2.0	A	2.0	A	0.6	A
SR 119/Tupman Rd.	0.8	A	0.9	A	1.0	A	3.4	A	5.4	A	3058.2	F*
Tupman Rd./Grace Ave.	7.0	A	7.0	A	8.0	A	7.1	A	7.1	A	13.9	B
Tupman Rd./Station Rd.	3.8	A	4.1	A	0.6	A	1.1	A	1.2	A	0.1	A
Dairy Rd./Stockdale Hwy.	1.5	A	1.4	A	7.4	A	0.6	A	0.5	A	22.1	C
Dairy Rd./Adohr Rd.	5.7	A	5.8	A	8.6	A	1.9	A	3.5	A	2.0	A

Source: HEI 2008c, pp. 5.10-16 and 17
[1] For existing intersection control features refer to **Traffic and Transportation Table 2**
*Degradation over the existing LOS to unacceptable level.

<u>Linear Facilities</u>

Project linear facilities include 8 miles of electrical transmission line, 8 miles of natural gas supply pipeline, 7 miles of potable water supply pipeline, and 4 miles in carbon dioxide pipeline. These linear facilities have the potential to result in temporary lane closures during stringing and tunneling activities. Traffic impacts from the construction of the linears would be short term in nature, mitigated by cones and flagmen when necessary, and are not expected to significantly impact traffic flow. Proposed Condition of Certification **TRANS-1** would ensure that the Construction Traffic Control Plan (prepared in conjunction with Kern County and Caltrans) identify any temporary closure of travel lanes or disruptions to street segments and intersections and ensure access to residential and/or commercial property during transmission line stringing activities or any other utility tie ins. This condition will mitigate any significant adverse impact on traffic flows on the local roadway system during construction of the linear facilities.

Operational Impacts and Mitigation

Once operational, the proposed HECA project would require daily vehicle trips to and from the site including regular deliveries of feedstock as well as operations and maintenance (O&M) trips, which includes the delivery of supplies, as well as employees traveling to and from the site for work (HEI 2008c, p. 5.10-13). Traffic and Transportation Table 6 lists the estimate of total peak daily operational related vehicle trip for the proposed HECA project, including identifying which of those would be generated during both the A.M. and P.M. peak hour periods.

Traffic and Transportation Table 6
Estimated Average and Peak Hour Trip Generation – Peak Daily Operation

	Total Daily Trips	A.M. Peak Hour			P.M. Peak Hour		
		In	Out	Total	In	Out	Total
Total Operational Traffic in PCE[1]	**1,746**[2]	**178**	**108**	**286**	**108**	**178**	**286**

Source: HEI 2008c, p.5.10-13
[1]All truck related trips were converted to PCE, while passenger vehicles used for daily worker commute do not require conversion
[2]Total Daily Trips includes off-peak hour operational related trips

Based on the construction vehicle trip calculations presented in Traffic and Transportation Table 6, an analysis was conducted in the AFC to determine the impacts of operational related vehicle trips on current and future baseline levels of service for study area intersections. Traffic and Transportation Table 7 identifies the current and future (Year 2014) LOS anticipated with and without proposed project operational vehicle traffic added to critical intersections in the vicinity of the HECA site.

As shown in Traffic and Transportation Table 7, operations-related traffic associated with the project would not impact or deteriorate any project area intersections to below an LOS D (as described above, and LOS D threshold is utilized to determine intersection impacts per the Kern County General Plan Circulation Element). As noted in Table 7**, the operational related analysis assumes that intersection improvements required by Condition of Certification** TRANS-2 **would occur, and**

are considered a component of the existing street system in Year 2016 with project traffic conditions. Therefore, HECA project operations would have no impact on study area intersection LOS. Consequently, no operations-related mitigation measures are required.

Kern Council of Governments Regional Transportation Plan

California State Proposition 111, passed by voters in 1990, established a requirement that urbanized areas prepare and regularly update a Congestion Management Program (CMP). The purpose of the CMP is to monitor the performance of the countywide transportation system, develop programs to address near-term and long-term congestion, and better integrate transportation and land use planning. The Kern Council of Governments (KCOG), as the designated Congestion Management Agency for the Kern County region, must develop, adopt, and regularly update the CMP.

The 2007 KCOG Destination 2030 Regional Transportation Plan (RTP) identifies the I-5, SR 119, and SR 43 freeways as CMP roadways (KCOG 2007). The RTP identifies that all roadway segments on the Congestion Management network shall maintain a LOS E or better (KCOG 2007). As discussed above, proposed project construction traffic would impact both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections, which are projected to degrade to LOS F, thus violating designated KCOG RTP thresholds. However, Conditions of Certification **TRANS-1** and **TRANS-2** will reduce impacts from construction related trips to a less than significant level at these intersections. As shown in **Traffic and Transportation Table 7**, operations-related traffic associated with the project would not impact or deteriorate any project area intersections to below an LOS E. Therefore, less than significant impacts to CMP designated roadways would occur from construction- or operational-related HECA project traffic upon the implementation of Conditions of Certification **TRANS-1** and **TRANS-2**.

Airports

FAA Form 7460 completion is required if the proposed project would introduce (1) any construction or alteration of more than 200-feet in height above the ground level at its site, or (2) any construction or alteration of greater height than the imaginary surface extending outward and upward at the following applicable slope (100 to 1 for horizontal distance of 20,000 feet from the nearest point of the nearest runway) (FAA 2009a). As the HECA site is located approximately 4.6 miles southeast of the Elk Hills-Buttonwillow Airport, only FAA 7460 requirement (1) is applicable. The HECA project includes several structures taller than 200 feet, with the project’s tallest structure proposed being the carbon dioxide vent at 260 feet in height (HEI 2008c, p. 5.10-25).

Traffic and Transportation Table 7
Current and Anticipated Year 2016 With and Without Project Intersection Levels of Service - Operation

Intersection[1]	AM						PM					
	Current (2009)		2016 Without Project		2016 With Project		Current (2009)		2016 With Project		2016 With Project	
	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS	Delay	LOS
I-5 NB Ramp/Stockdale Hwy.	1.2	A	1.2	A	2.8	A	1.9	A	2.0	A	3.7	A
I-5 SB Ramp/Stockdale Hwy.	3.4	A	3.3	A	2.7	A	7.0	A	7.4	A	7.4	A
I-5 NB Ramp/SR 119	1.0	A	1.0	A	1.1	A	0.6	A	0.7	A	0.7	A
I-5 SB Ramp/SR 119	0.4	A	0.3	A	0.4	A	0.9	A	1.0	A	1.1	A
SR 119/SR 43	27.0	C	26.7	C	27.4	C	33.9	C	32.7	C	31.7	C
SR 43/Stockdale Hwy.	11.2	B	18.0	B	18.2	B	16.3	C	18.8	C	19.2	B
Stockdale Hwy./Morris Rd.	1.7	A	1.6	A	0.5	A	2.0	A	2.0	A	0.9	A
SR 119/Tupman Rd.[2]	0.8	A	11.8	B	12.3	B	3.4	A	12.4	B	12.9	B
Tupman Rd./Grace Ave.	7.0	A	7.0	A	7.1	A	7.1	A	7.1	A	7.2	A
Tupman Rd./Station Rd.	3.8	A	4.1	A	1.8	A	1.1	A	1.2	A	0.6	A
Dairy Rd./Stockdale Hwy.	1.5	A	1.5	A	6.6	A	0.6	A	0.5	A	5.9	A
Dairy Rd./Adohr Rd.	5.7	A	6.2	A	6.1	A	1.9	A	3.5	A	4.0	A

Source: HEI 2008c, pp. 5.10-19 and 20
[1] For existing intersection control features refer to **Traffic and Transportation Table 3**
[2] Assumed to be signalized in Year 2016 as part of Condition of Certification **TRANS-2**
*Degradation over the existing LOS to unacceptable level.

On February 23, 2010 the HECA applicant obtained from the FAA a Determination of No Hazard to Air Navigation, stating that all HECA structures would pose no safety impact to aircraft operations (FAA 2010a). This determination does include temporary construction equipment such as cranes, derricks, etc., which may be used during actual construction of the structure. Equipment which has a height greater than the studied structure requires separate notice to the FAA (FAA 2010a). To ensure compliance with the FAA 7460 Determination of No Hazard to Air Navigation, Condition of Certification **TRANS-3** is required to ensure that any temporary or permanent structure, including all appurtenances, that exceeds an overall height of 200-feet above ground level (AGL) be marked and/or lighted consistent with FAA Advisory Circular 70/7460-1, Obstruction Lighting/Marking Requirements. The incorporation of this condition would ensure less than significant impacts to Elk Hills-Buttonwillow Airport air traffic operations would occur. Therefore, the proposed project is consistent with both FAA and Kern County ALUCP LORS.

Using the longitude and latitude of the HECA carbon dioxide vent site (tallest structure proposed), the HECA project was run through the California Military Land Use Compatibility Analysis (CMLUCA) database to determine if the HECA site is located within 1,000 feet of a military installation, is located within military based special use airspace, or is located beneath a military designated low-level flight path (CMLUCA 2010). Based on the CMLUCA report, the proposed HECA project does not intersect with any military bases, special use airspaces, or low level flight paths (CMLUCA 2010).

HECA main gas turbine/heat recovery steam generator (HRSG) operation and wet cooling tower exhaust would result in thermal air plumes during project operation. Thermal plumes have the ability to impact low flying aircraft and could cause moderate to severe turbulence to low-flying aircraft above the HECA site. A plume velocity analysis was conducted for the HECA project and is presented in detail as APPENDIX TT-1 of this Preliminary Staff Assessment. As described in APPENDIX TT-1, worst-case analysis for plume sources was used (please refer to APPENDIX TT-1 for an explanation of these conditions). The worst-case airspace conditions used in the velocity calculations are a frequent natural occurrence and would presumably occur during the life of the power plant and potentially when small aircraft fly above HECA site.

For purposes of this analysis, a vertical velocity of 4.3 meters per second (m/s) plume average velocity has been determined as the critical velocity of concern to light aircraft. As shown in APPENDIX TT-1, the calculated worst case calm wind condition vertical plume average velocities from the HECA cooling towers are not predicted to exceed 4.3 m/s at heights at or above 500 feet above ground level (AGL), except in cases where there would be large visible plumes for the power block cooling tower. However, the calculated worst case calm wind condition vertical plume average velocities from the HECA gas turbine/HRSG are predicted to exceed 4.3 m/s at 760 feet AGL. Furthermore, vertical plume average velocities from the gasification flare are predicted to exceed 4.3 m/s at 1,670 feet AGL.

The vertical velocity from the equipment exhaust at a given height above the stack decreases as wind speed increases. However, the plume average vertical velocities for the gas turbine/HRSG and gasification flare will remain relatively high during calm or very low wind speed conditions. These low wind speed conditions lasting an hour or more occur reasonably frequently at the site location. Additionally, shorter periods of dead calm winds, lasting long enough to increase the vertical plume average velocity height up to its peak height, can occur even more often during hours with low average wind speeds. There are a number of other plume sources at the site which would not have plume average velocities above 4.3 m/s at heights of concern, but these sources would add to the overall air turbulence that would be experienced above the HECA project site.

As described above in the environmental setting discussion of airports, Elk Hills-Buttonwillow Airport runway 11/29 observes a recommended right turn traffic pattern when departing Runway 11 (to the northwest) and a recommended left turn traffic pattern when departing Runway 29 (to the southeast), directing aircraft toward the proposed HECA project site (AirNav 2009). While recommended traffic patterns of Elk Hills-Buttonwillow Airport direct traffic toward the HECA site, the proposed HECA project site is approximately 4.6 miles southeast of the Elk Hills-Buttonwillow Airport. As indicated, the Elk Hills-Buttonwillow Airport handled an average of 23 aircraft per week, of which 100% were transient general aviation (AirNav 2009). As these aircraft have the potential to fly below 1,670 feet AGL above the HECA site, staff concludes there is the potential for thermal plumes from the HECA project to impact aircraft utilizing Elk Hills-Buttonwillow Airport. Staff is proposing Condition of Certification **TRANS 4**, which will require the project owner to work with the FAA to notify all pilots using Elk Hills-Buttonwillow Airport and to update all airspace charts that include the HECA site to announce that invisible air plume hazards could exist and pilots should avoid direct overflight below 1,670 feet AGL.

All land within one-mile of the project site is classified as Prime Farmland by the California Department of Conservation (HEI 2008c, p. 5.4-10). Therefore, agricultural production in the vicinity of the HECA site may use aeronautic crop dusting aircraft that fly at a low altitude (500 feet and below) near and over the project site. Based on the findings in APPENDIX TT-1, HECA thermal plume sources could significantly impact crop dusting aircraft operations over the HECA site. To reduce this potential impact, staff is proposing Condition of Certification **TRANS-5**, which will require the project owner to advise the Kern County Agricultural Commissioners that crop-dusting aircraft should avoid direct overflight of the project site. To further reduce potential impacts related to crop dusting aircraft operations, staff is proposing Condition of Certification **TRANS-6**, which will require the project owner to include reflective devices to all transmission lines connecting to the HECA project. The incorporation of these conditions into the proposed project will reduce potential thermal plume impacts to low flying crop dusting aircraft to a less than significant level.

Hazards and Public Safety

Construction vehicle impacts to motorist and public safety would be minimized to the maximum extent feasible by proposed Condition of Certification TRANS-1. **TRANS-1** requires the preparation of a construction traffic control plan that includes use of flagging and covering open trenches, would minimize hazards due to possible backup as construction workers enter and exit the project site when their shifts begin and end, and would divert construction-related traffic to the maximum extent feasible away from residential areas.

There is also a potential for unexpected damage to roads by vehicles and equipment within the project area that could result in a roadway hazard to the public. Therefore, staff is proposing Condition of Certification TRANS-7, which would require that any road damaged by project construction be repaired to its original condition. This will ensure that any damage to local roadways will not be a safety hazard to motorists.

The use of oversize vehicles during construction can create a hazard to the public by limiting motorist views on roadways and by the obstruction of space. As described above in Traffic and Transportation Table 1, CVC Sections 35550-35559 establish guidelines for oversize vehicle loads. To ensure consistency with these applicable ordinances, staff is proposing Condition of Certification TRANS-8, which would require that all oversize vehicles used on public roadways during construction comply with Caltrans, Kern County, and other relevant jurisdictions limitations on vehicle sizes and weights, as well as oversize vehicle routes and any other applicable limitations or other relevant jurisdictional policies.

As discussed in the **Visual Resources** section in this Preliminary Staff Assessment (PSA) Appendix VR-2: Visible Plume Modeling Analysis, no ground fogging plumes from any of the proposed cooling towers would reach any roads that are located near the project site. Therefore, ground fogging plumes should not interfere with traffic visibility on Dairy Road, Adohr Road, and Station Road. Therefore, there would be no impact on ground traffic safety.

The implementation of Conditions of Certification **TRANS-1**, **TRANS-7**, and TRANS-8 **would ensure that the proposed project result in less than significant hazard and safety impacts to motorists and ensure project compliance to LORS pertaining to such.**

Another anticipated increase in traffic during project construction and operation would be truck trips, including delivery of hazardous materials and removal of wastes. For a discussion of the potential impacts related to the transport of hazardous materials please see the **Hazards and Hazardous Materials** section in this PSA.

Emergency Access

In the event of an emergency at the HECA project site during construction, emergency vehicles would likely use either Dairy Road or Tupman Road and existing driveways to access the project site. To maintain temporary access for emergency vehicles and allow for adequate access into the facility, proposed Condition of Certification TRANS-1 requires the preparation of a construction traffic control plan which includes the assurance of access and movement of emergency vehicles. Furthermore, all internal access roadways would be designed consistent with Kern County standards (per Kern County General Plan Circulation Element Policy 4, as described above in Traffic and Transportation Table 1**)** to provide adequate room for emergency vehicles to navigate within the facility boundaries and internal circulation roadways. As discussed in the

Worker Safety and Fire Protection section in this PSA, Condition of Certification **WORKER SAFETY-6** requires the project owner to identify and provide a second access point for emergency personnel to enter the site. This access point and the method of gate operation shall be submitted to the Kern County Fire Department for review and comment and to the CPM for review and approval. These conditions will ensure emergency access is provided during both HECA construction and operation, resulting in less than significant impacts to emergency access.

Parking

During construction, all temporary construction equipment laydown and parking, including construction parking, offices, and construction laydown areas, will be located within the proposed project site. (HEI 2008c, p. 5.10-2). Therefore, no off-site construction worker parking will occur during construction of the proposed project. Once operational, worker parking would be located within the HECA site. In a letter to staff dated April 13, 2010, Kern County indicated internal operational employee parking requirements to ensure consistency with County regulations. Staff is proposing Condition of Certification **TRANS-9** to ensure these requirements are met by the proposed HECA project. With the incorporation of this condition, both construction and operation of the proposed project will have no impact on parking resources serving the area.

Alternative Transportation

The nearest KRT bus line to the proposed HECA project site is the Buttonwillow Route located approximately 3.9 miles northwest of the project site (Kern County 2009b). Therefore, no local bus stops are in immediate proximity of the HECA site. Based on the 2001 Kern County Bicycle Plan and visual inspections of the proposed HECA site, no existing or planned bicycle facilities are within the immediate vicinity of the project site (Kern County 2001). To ensure pedestrian and bicycle safety along local roadways utilized during project construction, proposed Condition of Certification TRANS-1 requires the preparation of a construction traffic control plan which includes the ensurance of pedestrian and bicycle safety from construction vehicle travel route to the project site and identification of safety procedures for exiting and entering the site access gate. Less than significant impacts would occur to alternative transportation facilities or use during construction and operation of the proposed project.

CUMULATIVE IMPACTS AND MITIGATION

A project may result in a significant adverse cumulative impact where its effects are cumulatively considerable. *Cumulatively considerable* means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (Title 14, California Code Regulation, section 15130).

Continued development of the Kern County area has contributed to congestion on area roadways that would be used by HECA related traffic. However, consultation with Kern County Roads and Planning Department staff identified no cumulative projects within the immediate vicinity of the HECA site area that could potentially contribute cumulative added trips (HEI 2008c, p. 5.10-14). Consistent with the Kern County Roads Department requirements (HEI 2008c, p. 5.10-14), an annual ambient traffic growth of

2% was used to establish No Project baselines for Year 2014 construction and Year 2016 operations analysis scenarios, as shown in **Traffic and Transportation Tables 5** and **7**. Therefore, temporary and permanent roadway congestion resulting from the proposed HECA project that could combine with other projects and growth within the area was considered in the proposed project analysis.

Condition of Certification **TRANS-1,** which would require the applicant to prepare a Construction Traffic Control Plan prior to construction, would reduce the overall potential for temporary project construction traffic to contribute cumulatively to local area traffic delays. However, as discussed earlier, construction-related traffic associated with the proposed project could have the potential to contribute cumulatively to an increase in traffic that could be substantial in relation to the existing traffic load and capacity of two intersections: SR 43/Stockdale Highway and SR 119/Tupman Road. Condition of Certification **TRANS-2** is proposed and will require physical improvements at the SR 43/Stockdale Highway, SR 119/Tupman Road, Dairy Road/Stockdale Highway, and Dairy Road/Adohr Road intersections to reduce impacts from construction related trips at both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections. These improvements would not only reduce the proposed project potential to contribute to cumulative delays at these intersections, but expand capacity of these intersections for traffic associated with cumulative development that could overlap with the HECA construction schedule. Furthermore, as construction related traffic is temporary and short-term, with the intersection improvements required by Condition of Certification **TRANS-2** construction related traffic associated with the proposed project **is not considered by staff to have the potential to contribute to significant cumulative traffic impacts.** As shown in **Traffic and Transportation Table 7**, project operations would have no contribution to cumulative traffic delay or capacity constraints. Therefore, the proposed project’s cumulative contribution to this impact is considered less than significant.

Conditions of Certification **TRANS-3** through **TRANS-9** are proposed to reduce the proposed project’s potential to contribute cumulatively to aviation, roadway hazards, physical damage to local transportation facilities, and alternative transportation impacts. These conditions ensure that the proposed project’s cumulative contribution to these impacts is less than significant. Furthermore, as the proposed project results in no impacts to public parking facilities, it would not contribute cumulatively to any parking impacts.

Furthermore, it is assumed that all cumulative project development occurring with Kern County would include environmental review and mitigation similar to that for the proposed project (i.e. the development of a construction traffic control plan, necessary roadway improvements, etc.) and would require approval from all affected jurisdictions and agencies. Mitigation and approval of individual projects would reduce cumulative transportation and traffic impacts as well. As agency approval of projects is gained, jurisdictional staggering of project construction and timing may occur to further reduce any potential cumulative transportation and traffic impacts. Therefore, the proposed project would not have a considerable cumulative contribution to transportation and traffic impacts within the area.

HECA construction workforce traffic, construction truck traffic, and operational truck traffic would not disproportionately travel through areas with an identified high percentage of minority or low-income population. In addition, staff has determined that all significant direct or cumulative impacts specific to traffic and transportation resulting from the construction or operation of the project would either be less than significant or be reduced to a less-than-significant level. Therefore, the proposed project does not introduce traffic and transportation-related environmental justice issues.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Traffic and Transportation Table 8 provides a general description of applicable statutes, regulations, and standards adopted by the federal government, the State of California, and Kern County pertaining to traffic and transportation with which the project is required to comply. Conditions of certification have been proposed to ensure project consistency with a law, ordinance, regulation, or standard where it was not already mandated by federal or state regulations.

Traffic and Transportation Table 8
Project Compliance with Adopted Traffic and Transportation Laws, Ordinances Regulations, and Standards

Applicable Law	LORS Description and Project Compliance Assessment
Federal	
Title 14, CFR, section 77 (14 CFR 77)	Includes standards for determining physical obstructions to navigable airspace. Sets forth requirements for notice to the Federal Aviation Administration of certain proposed construction or alterations. Also provides for aeronautical studies of obstructions to air navigation to determine their effect on the safe and efficient use of airspace (including temporary flight restrictions).
	On February 23, 2010 the FAA filed a Determination of No Hazard to Air Navigation stating that all HECA structures would pose no safety impact to aircraft operations. To ensure compliance with the FAA 7460 Determination of No Hazard to Air Navigation, Condition of Certification **TRANS-2** is required to ensure that any temporary or permanent structure, including all appurtenances, that exceeds an overall height of 200-feet above ground level (AGL) be marked and/or lighted consistent with FAA Advisory Circular 70/7460-1, Obstruction Lighting/Marking Requirements.
CFR, Title 49, Subtitle B	Includes procedures and regulations pertaining to interstate and intrastate transport (includes hazardous materials program procedures) and specifies safety measures for motor carriers and motor vehicles that operate on public highways.
	Enforcement is conducted by state and local law enforcement agencies and through state agency licensing and ministerial permitting (e.g., California Department of Motor Vehicles licensing, Caltrans permits), and/or local agency permitting (e.g., Kern County Department of Public Works permits). For a discussion of the potential impacts related to the transport of hazardous materials, please see the **Hazardous Materials Management** section in this PSA.
State	
California Vehicle Code, division 2, chapter 2.5; div. 6,	Includes regulations pertaining to licensing, size, weight, and load of vehicles operated on highways; safe operation of vehicles; and the transportation of hazardous materials.

chap. 7; div. 13, chap. 5; div. 14.1, chap. 1 & 2; div. 14.8; div. 15	Enforcement is provided by state and local law enforcement agencies and through ministerial state agency licensing and permitting and/or local agency permitting. The use of oversize vehicles during construction can create a hazard to the public by limiting motorist views on roadways and by the obstruction of space by the oversize vehicle. Therefore, staff is proposing Condition of Certification TRANS-8, which would require that all oversize vehicles used on public roadways during construction comply with Caltrans, Kern County, and other relevant jurisdictions limitations on vehicle sizes and weights.
California Streets and Highway Code, division 1 & 2, chapter 3 & chapter 5.5	Includes regulations for the care and protection of state and county highways and provisions for the issuance of written permits.
	Enforcement is provided by state and local law enforcement and through ministerial state agency licensing and permitting and/or local agency permitting. There is also a potential for unexpected damage to roads by vehicles and equipment within the project area. Therefore, staff is proposing Condition of Certification TRANS-7, which would require that any road damaged by project construction be repaired to its original condition.
Local	
Kern County Airport Land Use Compatibility Plan (ALUCP)	Element Requires local agencies to ensure compatible land uses in the vicinity of existing or proposed airports; to coordinate planning at state, regional, and local levels; to prepare and adopt an airport land use plan; to review plans, regulations, or locations of agencies and airport operators; and to review and make recommendations regarding the land uses, building heights, and other issues relating to air navigation safety and promotion of air commerce.
	On February 23, 2010 the FAA filed a Determination of No Hazard to Air Navigation stating that all HECA structures would pose no safety impact to aircraft operations. To ensure compliance with the FAA 7460 Determination of No Hazard to Air Navigation, Condition of Certification **TRANS-2** is required to ensure that any temporary or permanent structure, including all appurtenances, that exceeds an overall height of 200-feet above ground level (AGL) be marked and/or lighted consistent with FAA Advisory Circular 70/7460-1, Obstruction Lighting/Marking Requirements. This condition and the FAA Determination of No Hazard to Air Navigation result in the HECA project complying with this Plan.
Kern County General Plan Transportation Element	• Chapter 2 (Circulation Element), Goal 5, specifies that all county roadways shall operate at a Level of Service (LOS) D or better; • Circulation Element Subsection 2.3.3 (Highway Plan), Goal 5, specifies that all county highways shall operate at a Level of Service (LOS) D or better; and • Circulation Element, Policy 4, specifies that as a condition of private development approval, developers shall build roads needed to access the existing road network. Developers shall build these roads to County standards unless improvements along state routes are necessary then roads shall be built to California Department of Transportation standards. Developers shall locate these roads (width to be determined by the Circulation Plan) along centerlines shown on the circulation diagram map unless otherwise authorized by an approved Specific Plan Line. Developers may build local roads along lines other than those on the circulation diagram map. Developers would negotiate necessary easements to allow this requirement.
	Construction traffic would impact both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections, which are projected to degrade to LOS F without mitigation, during the P.M. peak hour. Therefore, staff is proposing Condition of Certification **TRANS-1** and **TRANS-2,** which would require the applicant to prepare a Traffic Control Plan and intersection improvements prior to construction in order to reduce the impact of a decreased LOS at these intersections. In a letter to staff dated April 13, 2010, Kern County has indicated that Adohr Road and Tupman Road alignments require a dedication of 45’ and 55’ from the centerline of the roads. No facilities or structures can be constructed in this area.

	If a portion of the proposed facility needs to encroach into those dedications, then a General Plan Amendment would be required to delete or downgrade the alignment. This process requires a hearing before the Board of Supervisors and can only be heard once every 3 months at the scheduled General Plan Amendment window dates. To accommodate these restrictions, Condition of Certification **TRANS-2** requires project owner and/or construction contractor coordination with and approval by Kern County prior to making the intersection improvements specified in **TRANS-2**. Furthermore, all internal access roadways would be designed consistent with Kern County standards. As discussed in the **Worker Safety and Fire Protection** section in this PSA, Condition of Certification **WORKER SAFETY-6** requires the project owner to identify and provide a second access point for emergency personnel to enter the site. This access point and the method of gate operation shall be submitted to the Kern County Fire Department for review and comment and to the CPM for review and approval. These conditions will ensure HECA compliance with these Kern County General Plan Goals and Policies.
Kern County Regional Transportation Plan	Chapter 4 (Strategic Investments) of the Regional Transportation Plan (RTP) includes a listing of State highways and principal arterials within Kern County designated as part of the Congestion Management System, including level of service standards (LOS E or greater) for these designated CMP roadways.
	Both SR 43 and SR 119 are classified as CMP roadways by the Kern County RTP. Project construction traffic would impact both the SR 43/Stockdale Highway and SR 119/Tupman Road intersections, which are projected to degrade to LOS F without mitigation during the P.M. peak hour, thus violating designated KCOG RTP thresholds. However, Condition of Certification **TRANS-1** and **TRANS-2,** which would require the applicant to prepare a Traffic Control Plan and intersection improvements prior to construction, will reduce impacts from construction related trips on these intersections to a less than significant level.

NOTEWORTHY PUBLIC BENEFITS

Neither the applicant nor staff has identified any traffic-related benefits associated with the proposed HECA project. While the proposed project would include several improvements to existing intersections as a result of Condition of Certification **TRANS-2**, these improvements are necessary to mitigate potential construction traffic impacts to intersection LOS and are not considered to be public benefits.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff has not received any agency or public comments related to traffic and transportation.

CONCLUSIONS

Based on the list of significance thresholds identified above, staff has analyzed potential construction and operational impacts by the proposed HECA project related to the regional and local traffic and transportation system and conclude the following:

- Conditions of Certification **TRANS-1** and **TRANS-2** should be implemented to ensure that all construction-related traffic and construction-related activities would not impact transportation facilities and existing traffic levels within the project area and to ensure that during operation, workforce and truck traffic to and from the facility would not result in a substantial increase in congestion, deterioration of the existing LOS, or creation of a traffic hazard during any time in the daily traffic cycle and would have a less than significant adverse impact along the routes or roadway intersections that would be used to access the HECA site.

- Condition of Certification **TRANS-3** should be implemented to ensure that all project components over 200-feet in height would have all the lighting and marking required by the FAA so they do not create a hazard to air navigation.
- Condition of Certification **TRANS-4** should be implemented to ensure the project owner works with the FAA to notify all pilots using the Elk Hills-Buttonwillow Airport and updates all airspace charts that include the HECA site to announce that invisible air plume hazards could exist and pilots should avoid direct overflight below 1,670 feet AGL.
- Conditions of Certification **TRANS-5** and **TRANS-6** should be implemented to ensure that thermal plumes associated with the proposed project do not impact crop dusting aircraft associate with use of adjacent agricultural land.
- Condition of Certification **TRANS-7** should be implemented to ensure that any road damaged by project construction be repaired to its original condition.
- Condition of Certification **TRANS-8** should be implemented to ensure that all oversize vehicles used on public roadways during construction comply with Caltrans and Kern County limitations on vehicle sizes and weights, as well as oversize vehicle routes and any other applicable limitations or other relevant jurisdictional policies.
- No off-site construction worker parking is anticipated for the construction of the proposed HECA project, as construction worker parking would be located within the project site. Condition of Certification **TRANS-9** should be implemented to ensure that all project proposed employee parking is consistent with Kern County requirements.
- No local rail lines or bus stops are in immediate proximity of the proposed project site. Condition of Certification **TRANS-1** should be implemented to ensure pedestrian and bicycle safety along travel routes of construction vehicles to the project site, as well as the identification of safety procedures for exiting and entering the site access gate.

Should the Energy Commission certify the project, staff recommends that the Energy Commission adopt the following conditions of certification.

PROPOSED CONDITIONS OF CERTIFICATION

TRANS-1 The project owner shall consult with Kern County and prepare and submit to the Compliance Project Manager (CPM) for approval a construction traffic control plan and implementation program. The traffic control plan must be prepared in accordance with Caltrans Manual on Uniform Traffic Control Devices and the WATCH Manual and must include but not be limited to the following issues:

- timing of heavy equipment and building materials deliveries
- redirecting construction traffic with a flag person
- signing, lighting, and traffic control device placement if required
- need for construction work hours and arrival/departure times outside peak traffic periods
- ensurance of access for emergency vehicles to the project site
- temporary closure of travel lanes or disruptions to street segments and intersections during transmission line stringing activities or any other utility tie ins
- access to residential and/or commercial property located near transmission line routes or any other utility tie ins
- ensurance of pedestrian and bicycle safety from construction vehicle travel routes to the project site, avoiding residential neighborhoods to the maximum extent feasible
- identification of safety procedures for exiting and entering the site access gate

Verification: At least 30 days prior to site mobilization, the project owner or contractor shall provide to the CPM a copy of the referenced documents for review and approval.

TRANS-2 The project owner shall coordinate with Kern County to construct intersection improvements needed to support construction traffic so that intersections will operate at an acceptable LOS, including:

- Intersection of SR 43 and Stockdale Highway: signalization of the current 4-way-Stop intersection.
- Intersection of SR 119 and Tupman Road: signalization of the current 2-way-stop intersection.
- Intersection of Dairy Road and Stockdale Highway: construct a separate left-turn lane on the westbound approach of Stockdale Highway, and a separate right-turn lane on the northbound approach of Dairy Road.
- Intersection of Dairy Road and Adohr Road: reconstruct the intersection to accommodate the turning radius needed by large trucks to make required turns.

Verification: At least 30 days prior to site mobilization, the project owner shall provide to the CPM photographic evidence and coordination documents with Kern County that these intersection improvements have been completed and are fully functional.

TRANS-3 The project owner shall ensure that all temporary and permanent HECA project components over 200-feet in height shall have lighting and marking consistent with FAA Advisory circular 70/7460-1 K Change 2, Obstruction

Marking and Lighting, red lights - Chapters 4,5(Red), & 12 so not to create a hazard to air navigation.

<u>Verification:</u> The project owner shall submit FAA Form 7460-2, Notice of Actual Construction or Alteration, to the FAA at least 10 days prior to start of construction (7460-2, Part I) and within 5 days after the construction reaches its greatest height (7460-2, Part II). A copy of these forms shall be provided to the CPM. Furthermore, at least 30 days prior to project operation, the Project Owner shall provide to the CPM pictures of any HECA project components over 200-feet in height after the FAA required lighting and marking have been completed.

TRANS-4 Prior to start-up and testing activities of the plant and all related facilities, the project owner shall work with the FAA to notify all pilots using the Elk Hills-Buttonwillow Airport and airspace above HECA site of potential air hazards. These activities would include, but not be limited to, the applicant's working with the FAA in issuing a notice to airmen (NOTAM) of the identified air hazard and updating the Terminal Area Chart and all other FAA-approved airspace charts used by pilots that include the HECA site to indicate that pilots should avoid overflight below 1,670 feet AGL. The applicant shall work with Elk Hills-Buttonwillow Airport to modify the Airport Facility Directory (AFD) to show the location of the HECA site on a map or figure and put in a remark about thermal plumes could cause moderate to severe turbulence, and therefore, pilots should avoid direct overflight below 1,670 feet. The applicant shall also work with the FAA and/or Elk Hills-Buttonwillow Airport to add a caution to the Automatic Weather Observation System (AWOS) recommending that pilots should avoid direct overflight below 1,670 feet AGL of the airspace above the HECA site.

<u>Verification:</u> At least 60 days prior to start of project operation, the project owner shall submit to the CPM for review copies of requests to the FAA and Elk Hills-Buttonwillow Airport requesting the incorporation of the project into the NOTAM, Terminal Area Chart, and Airport Facility Directory and any subsequent correspondence with these organizations.

TRANS-5 Prior to start-up and testing activities, the project owner shall notify the Kern County Agricultural Commissioners that due to the potential presence of project thermal plumes with significant size and velocities, crop dusting aircraft should avoid direct overflight of the HECA site.

<u>Verification:</u> At least 60 days prior to start-up and testing activities, the project owner shall provide the CPM with a copy of letters advising the Kern County Agricultural Commissioners that crop dusting aircraft should avoid direct overflight of the HECA site.

TRANS-6 The project owner shall include power line marking balls on the proposed 230 kV transmission line interconnect between the HECA site and PG&E Midway Substation along any segments adjacent to agricultural land uses utilizing crop dusting aircraft activities.

<u>Verification:</u> Prior to start-up and testing activities, the project owner shall provide to the CPM pictures of HECA project transmission line after the installation of marking balls has been completed.

TRANS-7 Following completion of project construction, the project owner shall repair any damage to roadways affected by construction activity along with the primary roadways identified in the traffic control plan for construction traffic to the road's pre-project construction condition. Prior to the start of construction, the project owner shall photograph, videotape, or digitally record images of the roadways that will be affected by all utility line construction and heavy construction traffic. The project owner shall provide the CPM, Kern County, and/or Caltrans with a copy of the images for the roadway segments under its jurisdiction. Also prior to start of construction, the project owner shall notify the County and/or Caltrans about the schedule for project construction. The purpose of this notification is to postpone any planned roadway resurfacing and/or improvement projects until after the project construction has taken place and to coordinate construction-related activities associated with other projects.

Verification: Within 30 days after completion of the project, the project owner shall meet with the CPM and Kern County to determine and receive approval for the actions necessary and schedule to complete the repair of identified sections of public roadways to original or as near-original condition as possible. Following completion of any regional road improvements, the project owner shall provide to the CPM a letter from Kern County and/or Caltrans if work occurred within its jurisdictional public right-of-way stating its satisfaction with the road improvements.

TRANS-8 The project owner shall comply with Caltrans, Kern County, and other relevant jurisdictions limitations on vehicle sizes, weights, and travel routes. In addition, the project owner shall obtain all necessary transportation permits from Caltrans, Kern County, and other relevant jurisdictions for roadway use.

Verification: In the Monthly Compliance Reports, the project owner shall submit copies of any permits received during that reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file for at least six months after the start of commercial operation.

TRANS-9 Standard vehicle parking spaces shall be 9 feet by 20 feet or larger in size and shall be designated by white painted stripes. A maximum of 20% of the required parking spaces may be designated compact spaces and shall be 8 feet by 16 feet or larger in size.

Verification: At least 30 days prior to site mobilization, the project owner shall meet with the CPM and Kern County to ensure final site design and approval include necessary parking design requirements.

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APPENDIX TT-1
PLUME VELOCITY ANALYSIS
Testimony of William Walters, P.E.

INTRODUCTION

The following provides the assessment of the Hydrogen Energy California (HECA) power plant project cooling towers, gas turbine/heat recovery generator (HRSG), and gasification flare exhaust stack plume velocities. Staff completed calculations to determine the worst-case vertical plume velocities at different heights above the stacks based on the applicant's proposed facility design.

PROJECT DESCRIPTION

The proposed project includes four large cooling towers, one General Electric (GE) Energy Frame 7FB combustion turbine-generator (CTG)/HRSG exhaust, and a gasification flare. There are a few other proposed exhaust sources, including a couple of small flares, a CO_2 vent, an auxiliary boiler, and two emergency engines; however, these other exhaust sources were found to have vertical plume velocity potentials that are well below the staff threshold of concern at 500 feet above ground level and therefore are not discussed further in this analysis. This project is designed as a base load facility that would operate year round.

PLUME VELOCITY CALCULATION METHOD

Staff has selected a calculation approach from a technical paper (Best 2003) to estimate the worst-case plume vertical velocities for the HECA exhausts. The calculation approach, which is also known as the "Spillane approach", used by staff is limited to calm wind conditions, which are the worst-case wind conditions. The Spillane approach uses the following equations to determine vertical velocity for single stacks during dead calm wind (i.e. wind speed = 0) conditions:

(1) $(V*a)^3 = (V*a)_o^3 + 0.12*F_o*[(z-z_v)^2-(6.25D-z_v)^2]$

(2) $(V*a)_o = V_{exit}*D/2*(T_a/T_s)^{0.5}$

(3) $F_o = g*V_{exit}*D^2*(1-T_a/T_s)/4$

(4) $Z_v = 6.25D*[1-(T_a/T_s)^{0.5}]$

Where: V = vertical velocity (m/s), plume-average velocity
a = plume top-hat radius (m, increases at a linear rate of $a = 0.16*(z- z_v)$
F_o= initial stack buoyancy flux m^4/s^3
z = height above ground (m)
z_v= virtual source height (m)
V_{exit}= initial stack velocity (m/s)
D = stack diameter (m)

T_a= ambient temperature (K)
T_s= stack temperature (K)
g = acceleration of gravity (9.8 m/s^2)

Equation (1) is solved for V at any given height above ground that is above the momentum rise stage for single stacks (where z > 6.25D) and at the end of the plume merged stage for multiple plumes. This solution provides the plume-average velocity for the area of the plume at a given height above ground; the peak plume velocity would be two times higher than the plume-average velocity predicted by this equation. As can be seen the stack buoyancy flux is a prominent part of Equation (1). The calm condition calculation basis clearly represents the worst-case conditions, and the vertical velocity will decrease substantially as wind speed increases.

For multiple stack plumes, where the stacks are equivalent, the multiple stack plume velocity during calm winds was calculated by staff in a simplified fashion, presented in the Best Paper as follows:

(5) $V_m = V_{sp}*N^{0.25}$

Where: V_m = multiple stack combined plume vertical velocity (m/s)
V_{sp} = single plume vertical velocity (m/s), calculated using Equation (1)
N = number of stacks

Staff notes that this simplified multiple stack plume velocity calculation method predicts somewhat lower velocity values than the full Spillane approach methodology as given in data results presented in the Best paper (Best 2003). However, the use of this approach on long linear cooling towers such as the power block cooling tower designed for the HECA project will likely over predict the combined plume velocities. To partially address this issue staff has not combined the stacks for the adjacent power block and gasification block cooling towers velocity analysis.

VERTICAL PLUME VELOCITY ANALYSIS

COOLING TOWERS DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the project's three cooling towers are provided in **Plume Velocity Tables 1-3**.

Plume Velocity Table 1
ASU Cooling Tower Operating and Exhaust Parameters [a]

Parameter		Cooling Tower Design Parameters		
Number of Cells per Tower		4 Cells (1 by 4 Linear Design)		
Cell Height		55 feet (16.76 meters)		
Cell Stack Diameter		30 feet (9.14 meters)		
Tower Housing Length		199 feet (60.70 meters)		
Tower Housing Width		60 feet (18.29 meters)		
Case	**Inlet Air Ambient Condition**	**Heat Rejection Rate (MW/hr)**	**Exhaust Flow Rate (klbs/hr)**	**Exhaust Temperature (°F)**
4 Cells	20°F, 85% RH	93.6	15,400	62.0
4 Cells	39°F, 82% RH	93.6	15,100	71.7
4 Cells	65°F, 55% RH	93.6	14,700	82.3
4 Cells	115°F, 15% RH	93.6	14,200	94.5

Source: HEI 2009a, URS 2009g, URS 2010a
Notes:
a. Values were extrapolated or interpolated between hourly ambient condition data points.

Plume Velocity Table 2
4-Cell Gasification Block Cooling Tower Operating and Exhaust Parameters [a]

Parameter		Cooling Tower Design Parameters		
Number of Cells per Tower		4 Cells (1 by 4 Linear Design)		
Cell Height		55 feet (16.76 meters)		
Cell Stack Diameter		30 feet (9.14 meters)		
Tower Housing Length		200 feet (60.99 meters)		
Tower Housing Width		60 feet (18.29 meters)		
Case	**Inlet Air Ambient Condition**	**Heat Rejection Rate (MW/hr)**	**Exhaust Flow Rate (klbs/hr)**	**Exhaust Temperature (°F)**
4 Cells	20°F, 85% RH	88.9	15,600	60.0
4 Cells	39°F, 82% RH	88.9	15,300	70.1
4 Cells	65°F, 55% RH	88.9	14,900	81.0
4 Cells	115°F, 15% RH	88.9	14,400	93.5

Source: HEI 2009a, URS 2009g, URS 2010a
Notes:
a. Values were extrapolated or interpolated between hourly ambient condition data points.

Plume Velocity Table 3
13-Cell Power Block Cooling Tower Operating and Exhaust Parameters [a]

Parameter		Cooling Tower Design Parameters		
Number of Cells per Tower		13 Cells (1 by 13 Linear Design)		
Cell Height		55 feet (16.76 meters)		
Cell Stack Diameter		30 feet (9.14 meters)		
Tower Housing Length		650 feet (198.21 meters)		
Tower Housing Width		60 feet (18.29 meters)		
Inlet Air Ambient Condition	No. Cells in Operation	Heat Rejection Rate (MW/hr)	Exhaust Flow Rate (klbs/hr)	Exhaust Temperature (°F)
Hydrogen Rich Fuel with No Duct Firing				
20°F, 85% RH	7	248.5	34,600	67.3
39°F, 82% RH	9	248.7	42,500	70.3
65°F, 55% RH	13	250.5	58,100	75.1
115°F, 15% RH	13	248.8	56,300	88.6
Hydrogen Rich Fuel with Duct Firing				
20°F, 85% RH	8	292.2	38,200	69.8
39°F, 82% RH	11	294.6	50,200	70.3
65°F, 55% RH	13	297.5	58,000	78.1
115°F, 15% RH	13	307.7	55,900	91.8
Natural Gas with No Duct Firing				
20°F, 85% RH	3	152.5	18,600	71.6
39°F, 82% RH	4	151.3	22,700	73.5
65°F, 55% RH	8	150.6	39,400	73.2
115°F, 15% RH	13	152.2	56,800	83.6
Natural Gas with Duct Firing				
20°F, 85% RH	6	231.9	30,400	69.2
39°F, 82% RH	8	231.3	38,500	70.9
65°F, 55% RH	13	231.0	58,500	73.7
115°F, 15% RH	13	232.9	56,300	88.0

Source: HEI 2009a, URS 2009g, URS 2010a
Notes:
a. Values were extrapolated or interpolated between hourly ambient condition data points.

For the worst-case analysis for these three plume sources the 65°F ambient condition exhaust case was selected to determine the worst case exhaust velocity conditions. Additionally, for the power block cooling tower the hydrogen rich fuel with no duct firing operating case was selected. The ambient condition was selected as lower temperature cases would have large visible plumes that pilots would be able to see and avoid. The power block cooling tower operating case was selected as by design it should be the most frequent operating case and duct firing would be expected to be limited to higher temperature summer periods with high electrical demand, which wouldn't be expected during very low temperature conditions.

GAS TURBINE/HRSG DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the gas turbine/HRSG stack exhaust are provided in **Plume Velocity Table 4**.

Plume Velocity Table 4
Gas Turbine/HRSG Exhaust Parameters [a]

Parameter	HRSG Exhaust Parameters		
Stack Height	213 feet (65 meters)		
Stack Diameter	6.1 feet (20 meters)		
Ambient Conditions	Moisture Content (% by weight)	Exhaust Flow Rate (klbs/hr)	Exhaust Temp (°F)
Hydrogen Rich Fuel with No Duct Firing			
20°F	7.9	4,082	194
39°F	8.0	4,086	199
65°F	8.4	4,102	200
115°F	8.9	4,015	203
Hydrogen Rich Fuel with Duct Firing			
20°F	8.8	1,095	193
39°F	8.9	4,099	198
65°F	9.3	4,115	200
115°F	10.2	4,032	203

Source: URS 2010a
Note: a. Values were extrapolated or interpolated between hourly ambient condition data points as necessary.

For the worst-case analysis for this plume source the 39°F ambient condition for the hydrogen rich fuel with no duct firing operating case was selected to determine the worst-case velocity conditions. This operating case was selected as by design it should be the most frequent operating case. Natural gas fuel operation should occur infrequently and has reduced vertical velocity potential due to lower exhaust temperatures. This ambient condition was selected as it is very close to the minimum temperature (41°F) where no visible plumes were predicted for this operating case and the hourly temperature was found to drop below 39°F only 3% of the time.

GASIFICATION FLARE DESIGN AND OPERATING PARAMETERS

The design and operating parameter data for the gasification flare stack exhaust are provided in **Plume Velocity Table 5**.

Plume Velocity Table 5
Gasification Flare Exhaust Parameters

Ambient Case	Gasification Flare 65°F
Stack Height	250 feet (76.2 meters)
Stack Diameter	17.9 feet (5.47 meters)
Stack Velocity	65.5 ft/sec (20 m/s)
Exhaust Temperature	1,832°F (1,273°K)

Source: URS 2009g

For the worst-case analysis for this plume source an average annual 65°F ambient condition is selected for this intermittent emission source.

PLUME VELOCITY CALCULATION RESULTS

Using the Spillane calculation approach, the plume average velocity at different heights above ground was determined by staff for calm conditions. Staff's calculated plume average velocity values are provided in **Plume Velocity Table 6.** The combined cooling tower velocities are calculated by combining the adjacent cells per Equation 5. The values provided below assume the multiple cooling tower cell plumes have completely merged.

Plume Velocity Table 6
HECA Exhaust Sources Worst-Case Predicted Plume Velocities (m/s)

Height (ft)	ASU Cooling Tower 65°F	Gasification Block Cooling Tower 65°F	Power Block Cooling Tower 65°F	Gas Turbine/HRSG 39°F	Gasification Flare 65°F
300	3.76	3.75	5.62	[a]	[a]
400	3.25	3.22	4.48	7.10	9.93
500	2.95	2.91	3.88	5.64	8.17
600	2.74	2.69	3.51	4.94	7.15
700	2.58	2.53	3.25	4.50	6.50
800	2.45	2.41	3.05	4.19	6.03
900	2.35	2.30	2.90	3.96	5.68
1,000	2.26	2.21	2.77	3.77	5.39
1,100	2.18	2.14	2.67	3.61	5.15
1,200	2.12	2.07	2.58	3.48	4.95
1,300	2.06	2.01	2.50	3.36	4.78
1,400	2.00	1.96	2.43	3.26	4.63
1,500	1.96	1.92	2.37	3.17	4.50
1,600	1.91	1.87	2.31	3.09	4.38
1,700	1.87	1.83	2.26	3.02	4.27
1,800	1.84	1.80	2.22	2.95	4.18
1,900	1.80	1.76	2.17	2.89	4.09
2,000	1.77	1.73	2.13	2.84	4.00

Source: Staff calculations.
Note:
[a] – Plume velocities within the jet phase of the plume (within 6.25 diameters above the stack height) cannot be accurately determined using the calculation method employed by staff.

As explained in the Transportation and Traffic section a plume average vertical velocity of 4.3 m/s has been determined by staff to be the critical velocity of concern to light aircraft. The cooling tower exhausts were not found to have plume average velocities above 4.3 meters per second at or above 500 feet above ground level[1].

The gas turbine/HRSG plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 760 feet. This is a worst-case value that assumes full load operation during cold ambient temperatures with dead calm wind conditions from ground level to 760 feet above the ground. For other operating scenarios and higher ambient temperatures the top height for the 4.3 m/s velocities would be somewhat lower than this maximum value.

The gasification flare plume average velocity is calculated to drop below 4.3 m/s at a height of approximately 1,670 feet. This is a worst-case value that assumes worst case

[1] A separate worst case temperature condition (20°F) calculation was performed for the cooling towers and, while the cooling tower exhausts were found to have higher velocities, the plume average velocities for the ASU and gasification block cooling towers remained below 4.3 m/s at 500 feet or higher above ground level. The power block cooling tower plume average velocity was predicted to be as high as or higher than 4.3 m/s up to 810 feet above ground level. However, as previously noted the colder weather conditions that predict these higher velocities for the cooling tower also predict large visible water vapor plumes as high as or higher than 500 feet above ground depending on the exact operating scenario and ambient conditions. Pilots should be able to see and avoid large visible water vapor plumes.

operation during annual average ambient temperatures with dead calm wind conditions from ground level to 1,670feet above the ground. The predicted plume velocities would be marginally higher for lower ambient temperature conditions. However, it should also be noted that the gasification flare is expected to operate less than 200 hours per year.

The velocity values listed above in **Plume Velocity Table 6** are plume average velocities across the area of the plume. The maximum plume velocity, based on a normal Gaussian distribution, is two times the plume average velocity as shown in the table.

WIND SPEED STATISTICS

Plume Velocity Table 7 provides the hourly average wind speed statistics for Bakersfield from meteorological data collected and processed by the SJVAPCD for 2004 through 2008. Calm winds for the purposes of the reported monitoring station statistics are those hours with average wind speeds below a threshold wind velocity, which is generally less than 2 to 3 knots (approximately 1 to 1.5 m/s). Calm or very low wind speeds can also occur for shorter periods of time within each of the monitored average hourly conditions.

Plume Velocity Table 7
Wind Speed Statistics for Bakersfield

Wind Speed Statistics	
Wind Speed	Percent
Calm	23.6%
≤ 1.5 m/s	35.8%
≤ 2.1 m/s	42.7%
≤ 2.6 m/s	51.7%

Source: Staff data reduction of SJVAPCD Bakersfield meteorological data from 2004-2008.

Calm/low wind speeds conditions averaging an hour or longer appear to be a frequent wind condition in the site area.

CONCLUSIONS

The calculated worst case calm wind condition vertical plume average velocities from the HECA cooling towers are not predicted to exceed 4.3 m/s at heights at or above 500 feet above ground level, except in cases where there would be large visible plumes for the power block cooling tower. However, the calculated worst case calm wind condition vertical plume average velocities from the HECA gas turbine/HRSG (760 feet) and gasification flare (1,670 feet) are predicted to exceed 4.3 m/s at heights at or above 500 feet above ground level. There are a number of other plume sources at the site which would not have plume average velocities above 4.3 m/s at heights of concern, but these sources would add to the overall air turbulence that would be experienced above the HECA project site.

The vertical velocity from the equipment exhaust at a given height above the stack decreases as wind speed increases. However, the plume average vertical velocities for the gas turbine/HRSG and gasification flare will remain relatively high, and would exceed 4.3 m/s above 500 feet about ground level, during calm or very low wind speed conditions. These low wind speed conditions lasting an hour or more occur reasonably frequently at the site location. Additionally, shorter periods of dead calm winds, lasting long enough to increase the vertical plume average velocity height up to its peak height, can occur even more often during hours with low average wind speeds.

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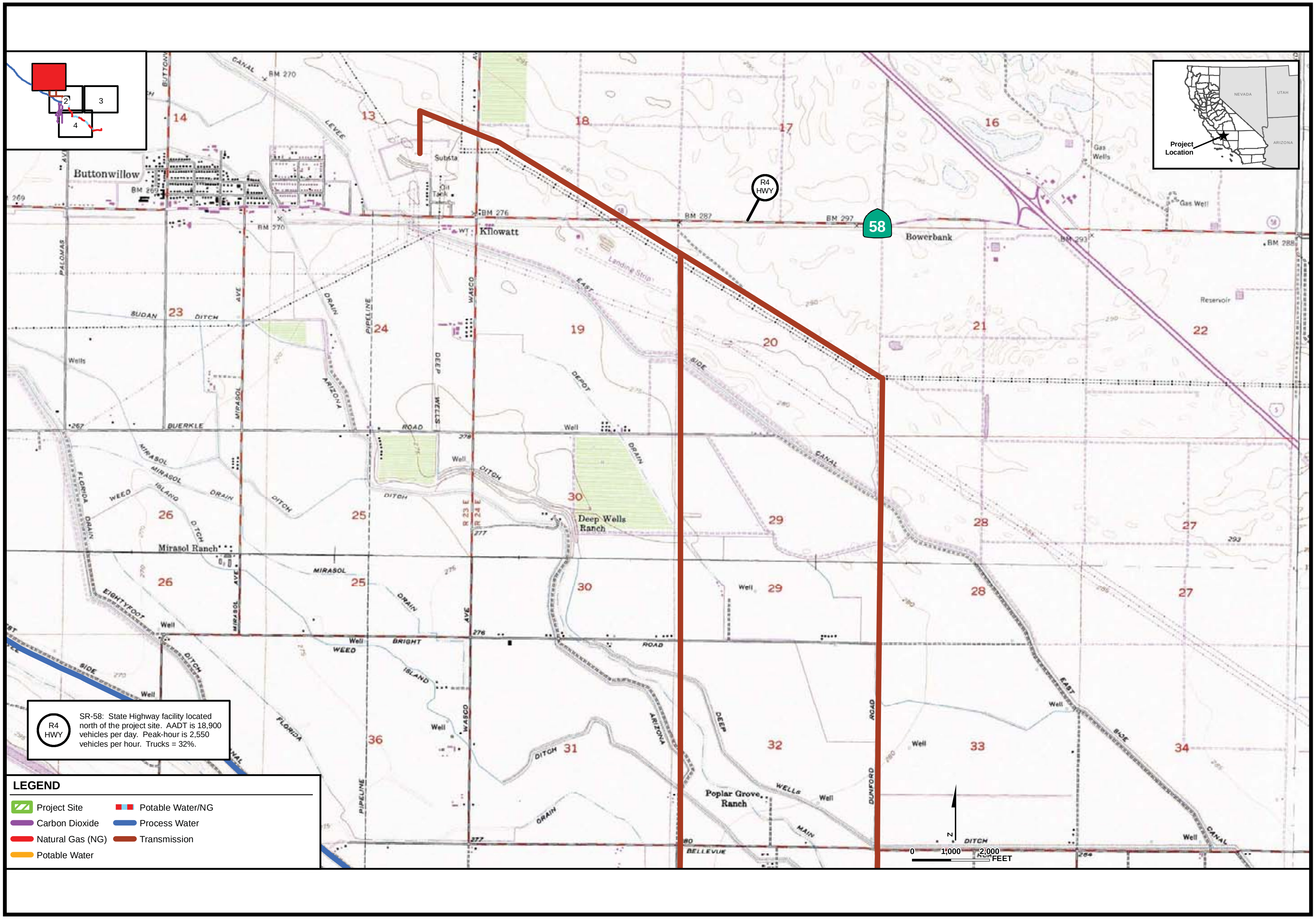
TRAFFIC AND TRANSPORTATION - FIGURE 1-1

Hydrogen Energy California - Transportation Setting of the Local Project Area and Affected Roadways

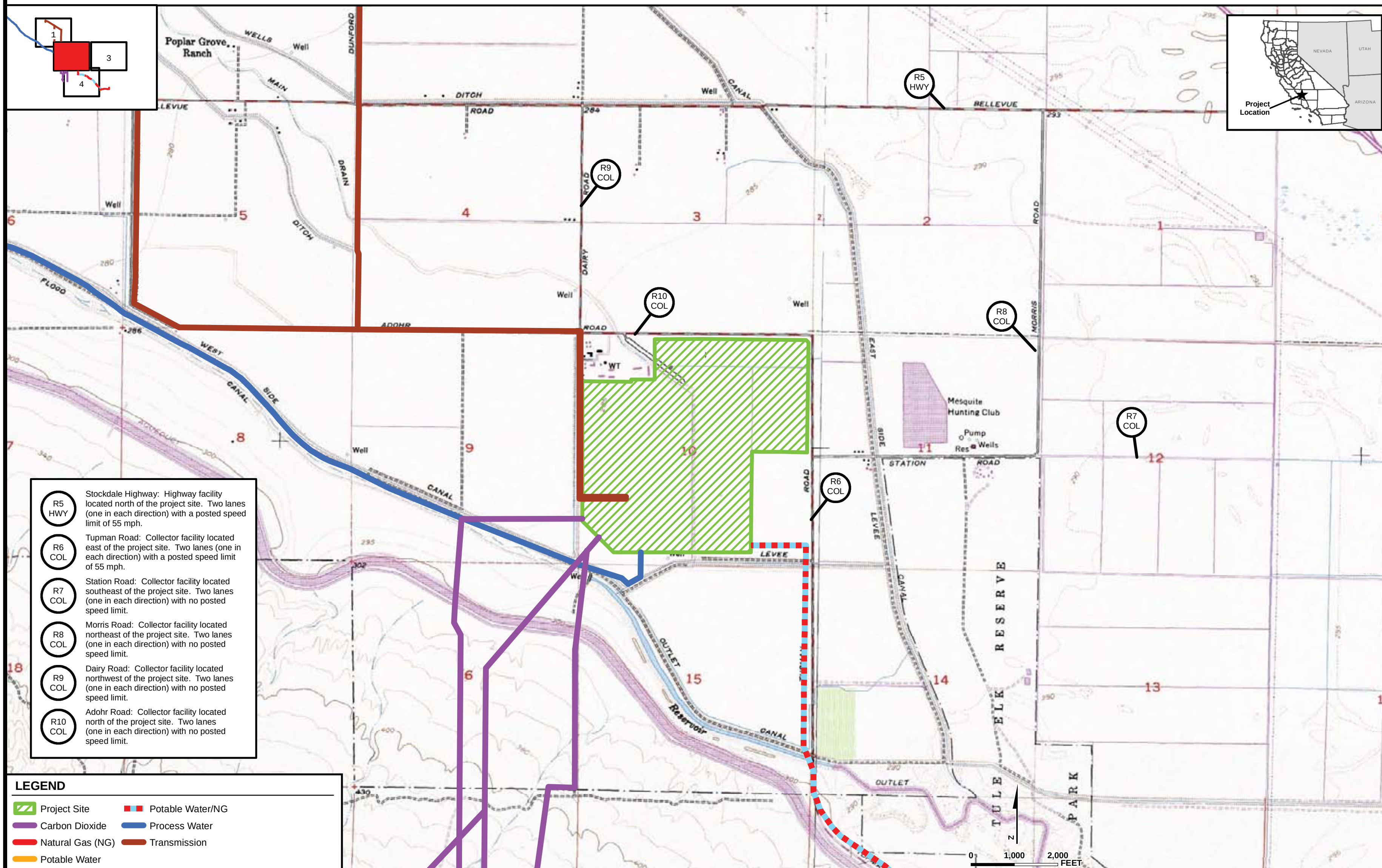


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: AFC Figure 5.10-2

TRAFFIC AND TRANSPORTATION - FIGURE 1-2

Hydrogen Energy California - Transportation Setting of the Local Project Area and Affected Roadways

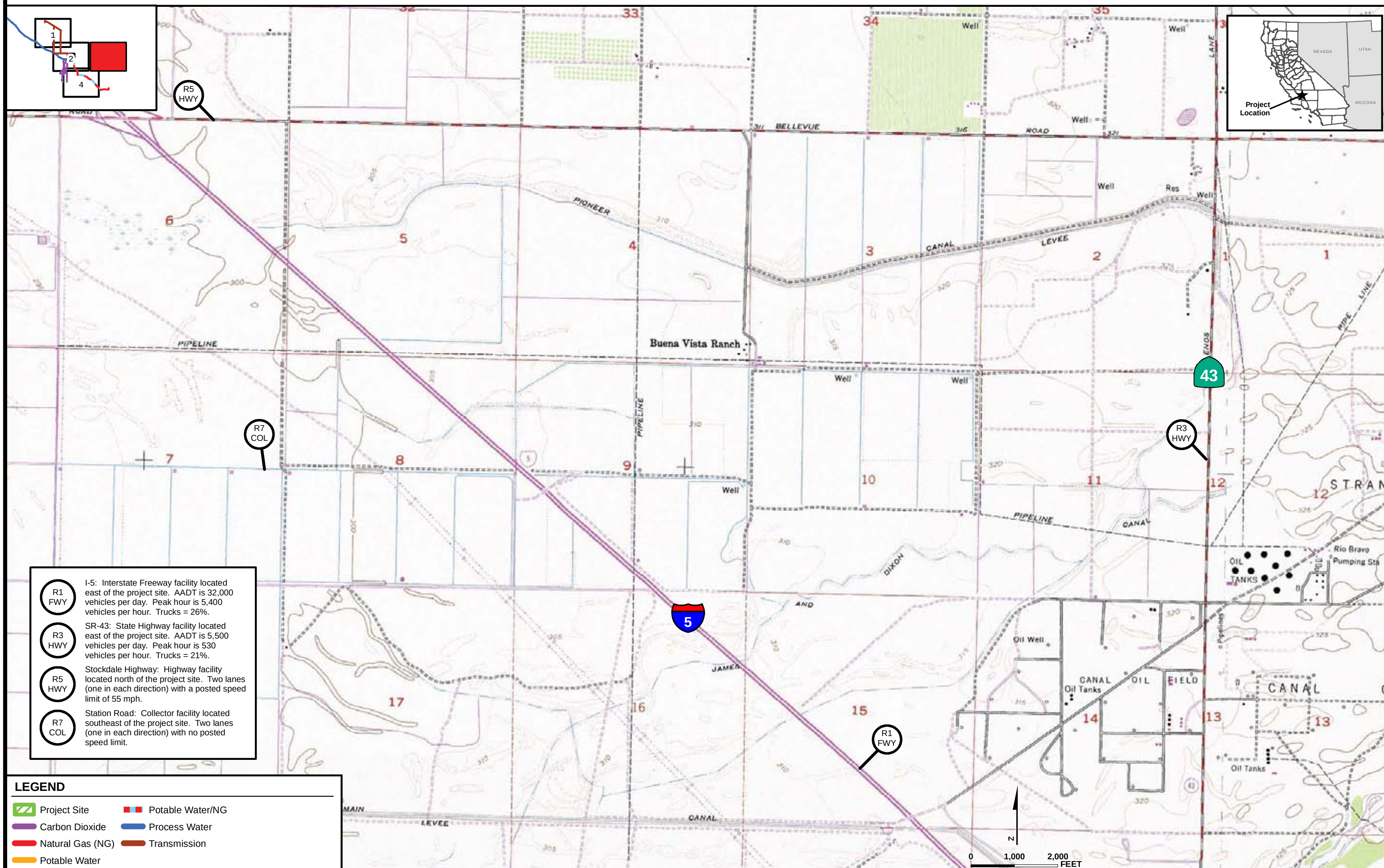


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: AFC Figure 5.10-2

TRAFFIC AND TRANSPORTATION - FIGURE 1-3

Hydrogen Energy California - Transportation Setting of the Local Project Area and Affected Roadways

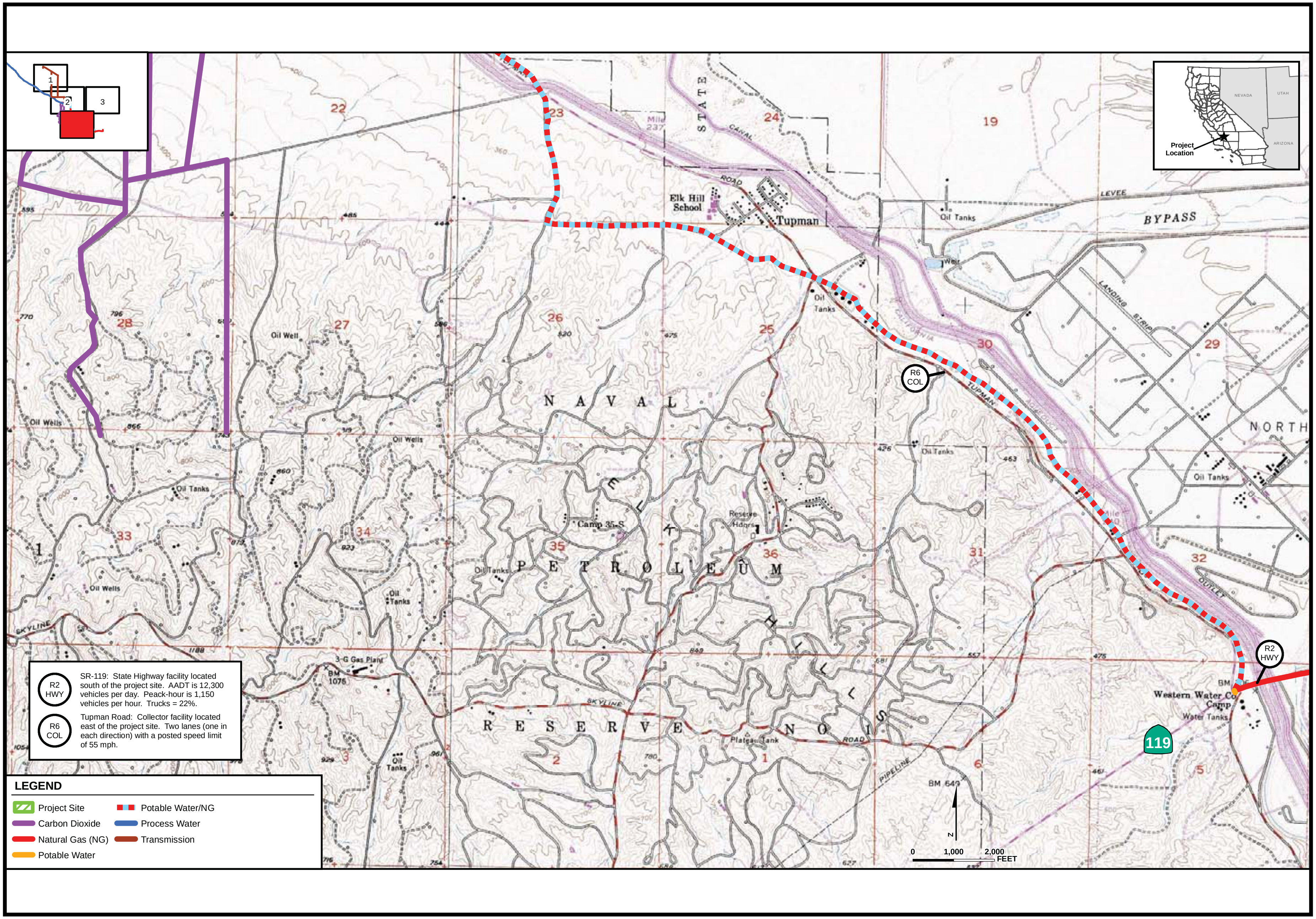


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: AFC Figure 5.10-2

TRAFFIC AND TRANSPORTATION - FIGURE 1-4

Hydrogen Energy California - Transportation Setting of the Local Project Area and Affected Roadways



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: AFC Figure 5.10-2

TRANSMISSION LINE SAFETY AND NUISANCE

Obed Odoemelam, Ph.D.

SUMMARY OF CONCLUSIONS

The applicant, Hydrogen Energy International, LLC, proposes to transmit the power from the proposed Hydrogen Energy California project to Pacific Gas and Electric's existing 230-kV Midway Substation approximately eight miles to the northwest and from which it would be delivered to the California Independent Operator-controlled power grid. Since the 230-kV line to be used would be operated within the PG&E service area, it would be constructed, operated, and maintained according to PG&E's guidelines for line safety and field management which conform to applicable laws, ordinances, regulations and standards. The two candidate routes for the line would each traverse a mostly agricultural area with no nearby residents thereby eliminating the potential for residential electric and magnetic field exposures. With the four proposed conditions of certification, any safety and nuisance impacts from construction and operation of the proposed line would be less than significant for either route.

INTRODUCTION

The purpose of this staff analysis is to assess the transmission line design and operational plan for the proposed Hydrogen Energy California (HECA) project to determine whether its related field and non-field impacts as expected from two candidate routes would constitute a significant environmental hazard in the surrounding areas; the line would be eight miles long in either of the proposed routes which would traverse the same general area for the connection to the PG&E Midway Substation. All related health and safety laws, ordinances, regulations, and standards (LORS) are currently aimed at minimizing such hazards. Staff's analysis focuses on the following issues taking into account both the physical presence of the line and the physical interactions of its electric and magnetic fields:

- aviation safety;
- interference with radio-frequency communication;
- audible noise;
- fire hazards;
- hazardous shocks;
- nuisance shocks; and
- electric and magnetic field (EMF) exposure.

The federal, state, and local laws and policies in the next section apply to the control of the field and nonfield impacts of electric power lines. Staff's analysis examines the project's compliance with these requirements.

METHODOLOGY AND THRESHOLDS FOR DETERMINING ENVIRONMENTAL CONSEQUENCES

The potential magnitude of the line impacts of concern in this staff analysis depends on compliance with the listed design-related LORS and industry practices. These LORS and practices have been established to maintain impacts below levels of potential significance. Thus, if staff determines that the project would comply with applicable LORS, we would conclude that any transmission line-related safety and nuisance impacts would be less than significant. The nature of these individual impacts is discussed below together with the potential for compliance with the LORS that apply.

Laws, Ordinances, Regulations, and Standards

TRANSMISSION LINE SAFETY AND NUISANCE (TLSN) TABLE 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Aviation Safety	
Federal	
Title 14, Part 77 of the Code of Federal Regulations (CFR),"Objects Affecting the Navigable Air Space"	Describes the criteria used to determine the need for a Federal Aviation Administration (FAA) "Notice of Proposed Construction or Alteration" in cases of potential obstruction hazards.
FAA Advisory Circular No. 70/7460-1G, "Proposed Construction and/or Alteration of Objects that May Affect the Navigation Space"	Addresses the need to file the "Notice of Proposed Construction or Alteration" (Form 7640) with the FAA in cases of potential for an obstruction hazard.
FAA Advisory Circular 70/7460-1G, "Obstruction Marking and Lighting"	Describes the FAA standards for marking and lighting objects that may pose a navigation hazard as established using the criteria in Title 14, Part 77 of the CFR.
Interference with Radio Frequency Communication	
Federal	
Title 47, CFR, section 15.2524, Federal Communications Commission (FCC)	Prohibits operation of devices that can interfere with radio-frequency communication.
State	
California Public Utilities Commission (CPUC) General Order 52 (GO-52)	Governs the construction and operation of power and communications lines to prevent or mitigate interference.
Audible Noise	
Local	
Kern County General Plan: Noise Element	References the county's Ordinance Code for noise limits.
Kern County: Noise Ordinance	Establishes performance standards for planned residential or other noise-sensitive land uses.

Applicable LORS	Description
Hazardous and Nuisance Shocks	
State	
CPUC GO-95, "Rules for Overhead Electric Line Construction"	Governs clearance requirements to prevent hazardous shocks, grounding techniques to minimize nuisance shocks, and maintenance and inspection requirements.
Title 8, California Code of Regulations (CCR) section 2700 et seq. "High Voltage Safety Orders"	Specifies requirements and minimum standards for safely installing, operating, working around, and maintaining electrical installations and equipment.
National Electrical Safety Code	Specifies grounding procedures to limit nuisance shocks. Also specifies minimum conductor ground clearances.
Industry Standards	
Institute of Electrical and Electronics Engineers (IEEE) 1119, "IEEE Guide for Fence Safety Clearances in Electric-Supply Stations"	Specifies the guidelines for grounding-related practices within the right-of-way and substations.
Electric and Magnetic Fields	
State	
GO-131-D, CPUC "Rules for Planning and Construction of Electric Generation Line and Substation Facilities in California"	Specifies application and noticing requirements for new line construction including EMF reduction.
CPUC Decision 93-11-013	Specifies CPUC requirements for reducing power frequency electric and magnetic fields.
Industry Standards	
American National Standards Institute (ANSI/IEEE) 644-1944 Standard Procedures for Measurement of Power Frequency Electric and Magnetic Fields from AC Power Lines	Specifies standard procedures for measuring electric and magnetic fields from an operating electric line.
Fire Hazards	
State	
14 CCR sections 1250-1258, "Fire Prevention Standards for Electric Utilities"	Provides specific exemptions from electric pole and tower firebreak and conductor clearance standards and specifies when and where standards apply.

SETTING AND EXISTING CONDITIONS

As discussed by the applicant, Hydrogen Energy International, LLC, (HEI), the proposed HECA project would be located on a 473-acre land parcel approximately 1.5 miles northwest of the unincorporated community of Tupman in unincorporated Kern County.

The project and related tie-in transmission line would be in an area primarily used for agricultural activities with no nearby residences. Two alternative routes for the transmission line have been proposed to each be approximately eight miles long as it extends from the project site in a mostly northwestern direction before entering the substation on its north side. The ultimate choice would depend on factors bearing on land availability, design considerations, line maintainability and ease of construction but the areas of field and nonfield impacts of potential concern to staff would essentially be the same (HEI 2009c, pp. 2-17, 2-74 and 2009f Figure 1). The applied design would also be the same for each route; therefore the same design- and operations-related conditions for certification would apply to the line in any chosen route. Since the nearest residence would be approximately 370 feet from either of the candidate routes (HEI 2009c pp. 5.6-3 and 5.4-5) there would not be the type of residential field exposure that has been of health concern in recent years.

PROJECT DESCRIPTION

The proposed tie-in line would consist of the following individual segments:

- A new, double-circuit 230-kV overhead transmission line extending 8 miles from the on-site project switchyard to PG&E's Midway Substation near the town of Buttonwillow to the northwest; and
- The project's on-site 230-kV switchyard from which the conductors would extend to the Midway Substation.

The proposed project line would have a 150-foot right-of-way within each candidate route.

The conductors would be aluminum steel-supported cables supported on steel towers or steel poles as typical of similar PG&E lines. The applicant provided the details of the proposed support structures as related to line safety, maintainability, and field reduction efficiency. These support structures would be spaced 700 feet apart with a minimum ground clearance of 40 feet which is significantly more than the CPUC-specified minimum of 30 feet (HEI 2009a, page 4-10, and Figures 4-2 and 4-33.4-39).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

DIRECT IMPACTS AND MITIGATION

Aviation Safety

Any potential hazard to area aircraft would relate to the potential for collision in the navigable airspace. The requirements in the LORS listed on **TLSN Table 1** establish the standards for assessing the potential for obstruction hazards within the navigable space and establish the criteria for determining when to notify the FAA about such hazards. These regulations require FAA notification in cases of structures over 200 feet from the ground, or if the structure were to be less than 200 feet in height but located within the restricted airspace in the approaches to public or military airports. For airports with runways longer than 3,200 feet, the restricted space is defined by the FAA as an area extending 20,000 feet from the runway. For airports with runways of 3,200 feet or less, the restricted airspace would be an area that extends 10,000 feet from this runway. For heliports, the restricted space is an area that extends 5,000 feet.

Buttonwillow Airport is located approximately 3.5 miles southwest of the connected Midway Substation potentially placing the proposed line's structures within the restricted airspace. However, to pose an aviation hazard according to FAA criteria, the line structure will have to be 160 feet in height or more. At a maximum of 115-feet in height, the erected line would not pose any aviation hazard within any of the candidate rotes (HEI 2009c, p. 4-13). Furthermore, the maximum height of 115 feet places the proposed line structures significantly below the 200-foot height that triggers the concern over aviation hazard according to FAA requirements. The other area airports are Ford City, Bakersfield and Gottlieb Airports. The Ford City Airport is located 14 miles south of Tupman; the Bakersfield Airport is located approximately 22 miles east of Tupman, with Gottlieb approximately 14 miles east of Buttonwillow. None of these airports is close enough for any line-related collision hazards. Therefore, staff does not recommend a condition of certification regarding aviation safety.

Interference with Radio-Frequency Communication

Transmission line-related radio-frequency interference is one of the indirect effects of line operation and is produced by the physical interactions of line electric fields. Such interference is due to the radio noise produced by the action of the electric fields on the surface of the energized conductor. The process involved is known as *corona discharge*, but is referred to as *spark gap electric discharge* when it occurs within gaps between the conductor and insulators or metal fittings. When generated, such noise manifests itself as perceivable interference with radio or television signal reception or interference with other forms of radio communication. Since the level of interference depends on factors such as line voltage, distance from the line to the receiving device, orientation of the antenna, signal level, line configuration and weather conditions, maximum interference levels are not specified as design criteria for modern transmission lines. The level of any such interference usually depends on the magnitude of the electric fields involved and the distance from the line. The potential for such impacts is therefore minimized by reducing the line electric fields and locating the line away from inhabited areas.

The proposed project lines would be built and maintained according to standard practices that minimize surface irregularities and discontinuities. Moreover, the potential for such corona-related interference is usually of concern for lines of 345 kV and above, and not for 230-kV lines such as the proposed line. The proposed low-corona designs are used for PG&E lines of similar voltage rating to reduce surface electric field gradients and the related potential for corona effects. Since the proposed lines would traverse a largely uninhabited agricultural area within each candidate route, staff does not expect any corona-related radio-frequency interference or related complaints and does not recommend any related condition of certification.

Audible Noise

The noise-reducing designs related to electric field intensity are not specifically mandated by federal or state regulations in terms of specific noise limits. As with radio noise, such noise is limited instead through design, construction, or maintenance practices established from industry research and experience as effective without significant impacts on line safety, efficiency, maintainability, and reliability. Audible noise usually results from the action of the electric field at the surface of the line conductor and could be perceived as a characteristic crackling, frying, or hissing sound or hum, especially in wet weather. Since the noise level depends on the strength of the line electric field, the potential for perception can be assessed from estimates of the field strengths expected during operation. Such noise is usually generated during rainfall, but mainly from overhead lines of 345 kV or higher. It is, therefore, not generally expected at significant levels from lines of less than 345 kV as proposed for HECA. Research by the Electric Power Research Institute (EPRI 1982) has validated this by showing the fair-weather audible noise from modern transmission lines to be generally indistinguishable from background noise at the edge of a right-of-way of 100 feet or more; the proposed line right-of-way would be 150 feet (HEI 2009c. p 4-8). Since the low-corona designs are also aimed at minimizing field strengths, staff does not expect the proposed line operation to add significantly to current background noise levels in the project area. For an assessment of the noise from the proposed project and related facilities, please refer to staff's analysis in the **Noise and Vibration** section.

Fire Hazards

The fire hazards addressed through the related LORS in **TLSN Table 1** are those that could be caused by sparks from conductors of overhead lines, or that could result from direct contact between the line and nearby trees and other combustible objects.

Standard fire prevention and suppression measures for similar PG&E lines would be implemented for the proposed project line (HEI 2009a, pp. 4-14 and 4.15). The applicant's intention to ensure compliance with the clearance-related aspects of GO-95 would be an important part of this mitigation approach. Condition of Certification **TLSN-3** is recommended to ensure compliance with important aspects of the fire prevention measures.

Hazardous Shocks

Hazardous shocks are those that could result from direct or indirect contact between an individual and the energized line, whether overhead or underground. Such shocks are capable of serious physiological harm or death and remain a driving force in the design and operation of transmission and other high-voltage lines.

No design-specific federal regulations have been established to prevent hazardous shocks from overhead power lines. Safety is assured within the industry from compliance with the requirements specifying the minimum national safe operating clearances applicable in areas where the line might be accessible to the public.

The applicant's stated intention to implement the GO-95-related measures against direct contact with the energized line (HEI 2009c, p.4-15) would serve to minimize the risk of hazardous shocks. Staff's recommended Condition of Certification **TLSN-1** would be adequate to ensure implementation of the necessary mitigation measures.

Nuisance Shocks

Nuisance shocks are caused by current flow at levels generally incapable of causing significant physiological harm. They result mostly from direct contact with metal objects electrically charged by fields from the energized line. Such electric charges are induced in different ways by the line's electric and magnetic fields.

There are no design-specific federal or state regulations to limit nuisance shocks in the transmission line environment. For modern overhead high-voltage lines, such shocks are effectively minimized through grounding procedures specified in the National Electrical Safety Code (NESC) and the joint guidelines of the American National Standards Institute (ANSI) and the Institute of Electrical and Electronics Engineers (IEEE). For the proposed project line, the project owner will be responsible in all cases for ensuring compliance with these grounding-related practices within the right-of-way.

The potential for nuisance shocks around the proposed line would be minimized through standard industry grounding practices (HEI 2009c, p. 4-14). Staff recommends Condition of Certification **TLSN-4** to ensure such grounding for HECA.

Electric and Magnetic Field Exposure

The possibility of deleterious health effects from EMF exposure has increased public concern in recent years about living near high-voltage lines. Both electric and magnetic fields occur together whenever electricity flows, and exposure to them together is generally referred to as *EMF exposure*. The available evidence as evaluated by the CPUC, other regulatory agencies, and staff has not established that such fields pose a significant health hazard to exposed humans. There are no health-based federal regulations or industry codes specifying environmental limits on the strengths of fields from power lines. Most regulatory agencies believe, as staff does, that health-based limits are inappropriate at this time. They also believe that the present knowledge of the issue does not justify any retrofit of existing lines.

Staff considers it important, as does the CPUC, to note that while such a hazard has not been established from the available evidence, the same evidence does not serve as proof of a definite lack of a hazard. Staff therefore considers it appropriate, in light of present uncertainty, to recommend feasible reduction of such fields without affecting safety, efficiency, reliability, and maintainability.

While there is considerable uncertainty about EMF health effects, the following facts have been established from the available information and have been used to establish existing policies:

- Any exposure-related health risk to the exposed individual will likely be small.
- The most biologically significant types of exposures have not been established.
- Most health concerns are about the magnetic field.
- There are measures that can be employed for field reduction, but they can affect line safety, reliability, efficiency, and maintainability, depending on the type and extent of such measures.

State's Approach to Regulating Field Exposures

In California, the CPUC (which regulates the installation and operation of many high-voltage lines owned and operated by investor-owned utilities) has determined that only no-cost or low-cost measures are presently justified in any effort to reduce power line fields beyond levels existing before the present health concern arose. The CPUC has further determined that such reduction should be made only in connection with new or modified lines. It requires each utility within its jurisdiction to establish EMF-reducing measures and incorporate such measures into the designs for all new or upgraded power lines and related facilities within their respective service areas. The CPUC further established specific limits on the resources to be used in each case for field reduction. Such limitations were intended by the CPUC to apply to the cost of any redesign to reduce field strength or relocation to reduce exposure. Publicly owned utilities, which are not within the jurisdiction of the CPUC, voluntarily comply with these CPUC requirements. This CPUC policy resulted from assessments made to implement CPUC Decision 93-11-013.

The CPUC has recently revisited the EMF management issue to assess the need for policy changes to reflect the available information on possible health impacts. The findings specified in Decision D.06-1-42 of January 2006, did not point to a need for significant changes to existing field management policies. Since there are no residences in the immediate vicinity of the proposed project line, there would not be the long-term residential EMF exposures mostly responsible for the health concern of recent years. The only project-related EMF exposures of potential significance would be the short-term exposures of plant workers, regulatory inspectors, maintenance personnel, visitors, or individuals in the vicinity of the line. These types of exposures are short term and well understood as not significantly related to the health concern.

In keeping with this CPUC policy, staff requires a showing that each proposed overhead line would be designed according to the safety and EMF-reducing design guidelines applicable to the utility service area involved. These field-reducing measures can impact line operation if applied without appropriate regard for environmental and other local factors bearing on safety, reliability, efficiency, and maintainability. Therefore, it is up to each applicant to ensure that such measures are applied in ways that prevent significant impacts on line operation and safety. The extent of such applications would be reflected by ground-level field strengths as measured during operation. When estimated or measured for lines of similar voltage and current-carrying capacity, such field strength values can be used by staff and other regulatory agencies to assess the effectiveness of the applied reduction measures. These field strengths can be estimated for any given design using established procedures. Estimates are specified for a height of one meter above the ground, in units of kilovolts per meter (kV/m), for the electric field, and milligauss (mG) for the companion magnetic field. Their magnitude depends on line voltage (in the case of electric fields), the geometry of the support structures, degree of cancellation from nearby conductors, distance between conductors, and, in the case of magnetic fields, amount of current in the line.

Since the CPUC currently requires that most new lines in California be designed according to the EMF-reducing guidelines of the electric utility in the service area involved, their fields are required under this CPUC policy to be similar to fields from similar lines in that service area. Designing the proposed project line according to existing PG&E field strength-reducing guidelines would constitute compliance with the CPUC requirements for line field management.

Industry's and Applicant's Approach to Reducing Field Exposures

The present focus is on the magnetic field because unlike electric fields, it can penetrate the soil, buildings, and other materials to produce the types of human exposures at the root of the health concern of recent years. The industry seeks to reduce exposure, not by setting specific exposure limits, but through design guidelines that minimize exposure in each given case. As one focuses on the strong magnetic fields from the more visible high-voltage power lines, staff considers it important, for perspective, to note that an individual in a home could be exposed to much stronger fields while using some common household appliances than from high-voltage lines (National Institute of Environmental Health Services and the U.S. Department of Energy, 1998). The difference between these types of field exposures is that the higher-level, appliance-related exposures are short term, while the exposures from power lines are lower level, but long term. Scientists have not established which of these types of exposures would be more biologically meaningful in the individual. Staff notes such exposure differences only to show that high-level magnetic field exposures regularly occur in areas other than around high-voltage power lines.

As with similar PG&E lines, specific field strength-reducing measures would be incorporated into the proposed line's design to ensure the field strength minimization currently required by the CPUC in light of the concern over EMF exposure and health.

The field reduction measures to be applied include the following:

1. increasing the distance between the conductors and the ground to an optimal level;
2. reducing the spacing between the conductors to an optimal level;
3. minimizing the current in the line; and
4. arranging current flow to maximize the cancellation effects from interacting of conductor fields.

Since the routes of the proposed project lines would have no nearby residences, the long-term residential field exposures at the root of the health concern of recent years would not be a significant concern. The field strengths of most significance in this regard would be as encountered at the edge of the line's 150-foot right-of-way. These field intensities would depend on the effectiveness of the applied field-reducing measures. The applicant calculated the maximum electric and magnetic field intensities expected along either of the proposed routes (HEI 2009c, pp. 4-11 through 4-13 and Figures 4-9 through 4-13). The maximum electric field strength was calculated as 0.12 kV/m at the edge of the 150-foot right-of-way while the maximum operational magnetic field strength was calculated as 24.4 mG at the same location. These field strength values are similar to those of similar PG&E lines (as required under current CPUC regulations) but, in the case of the magnetic field, the estimate is much less than the 200 mG currently specified by the few states with regulatory limits. The requirements in Condition of Certification **TLSN-2** for field strength measurements are intended to assess the applicant's assumed field reduction efficiency.

CUMULATIVE IMPACTS

Operating any given project may lead to significant adverse cumulative impacts when its effects are considered cumulatively considerable. "Cumulatively considerable" means in this context that the incremental effects of an individual project would be significant when considered together with the effects of past, existing, and future projects (California Code Regulation, Title 14, section 15130). When field intensities are measured or calculated for a specific location, they reflect the interactive, and therefore, cumulative effects of fields from all contributing conductors. This interaction could be additive or subtractive depending on prevailing conditions. Since the proposed project's transmission line would be designed, built, and operated according to applicable field-reducing PG&E guidelines (as currently required by the CPUC for effective field management), any contribution to cumulative area exposures should be at levels expected for PG&E lines of similar voltage and current-carrying capacity. It is this similarity in intensity that constitutes compliance with current CPUC requirements on EMF management. The actual field strengths and contribution levels for the proposed line design (in this project area with no nearby lines) would be assessed from the results of the field strength measurements specified in Condition of Certification **TLSN-2**. Since there are no nearby area lines, no cumulative safety and nuisance impacts from the combined interaction of fields from nearby lines are expected.

COMPLIANCE WITH LORS

As previously noted, current CPUC policy on safe EMF management requires that any high-voltage line within a given area be designed to incorporate the field strength-reducing guidelines of the main area utility lines to be interconnected. The utility in the case of HECA is PG&E. Since the proposed project's 230-kV line and related switchyards would be designed according to the respective requirements of the LORS listed in **TLSN Table 1**, and operated and maintained according to current PG&E guidelines on line safety and field strength management, staff considers the proposed design and operational plan to be in compliance with the health and safety requirements of concern in this analysis. The actual contribution to the area's field exposure levels would be assessed for the chosen route from results of the field strength measurements required in Condition of Certification **TLSN-2**.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff received no public or agency comments on the transmission line nuisance and safety aspects of the proposed HECA.

NOTEWORTHY PUBLIC BENEFITS

Since the proposed tie-in line would pose specific, although insignificant risks of the field and nonfield effects of concern in this analysis, its building and operation would not yield any public benefits regarding the effort to minimize any human risks from these impacts.

FACILITY CLOSURE

If the proposed HECA were to be closed and decommissioned, and all related structures are removed as described in the **Project Description** section, the minimal electric shocks and fire hazards from the physical presence of this tie-in line would be eliminated. Decommissioning and removal would also eliminate the line's field impacts assessed in this analysis in terms of nuisance shocks, radio-frequency impacts, audible noise, and electric and magnetic field exposure. Since the line would be designed and operated according existing PG&E guidelines, these impacts would be as expected for PG&E lines of the same voltage and current-carrying capacity and therefore, at levels reflecting compliance with existing health and safety LORS.

PROPOSED CONDITIONS OF CERTIFICATION

TLSN-1 The project owner shall construct the proposed 230-kV transmission line within either of the two candidate routes according to the requirements of California Public Utility Commission's GO-95, GO-52, GO-131-D, Title 8, and Group 2, High Voltage Electrical Safety Orders, sections 2700 through 2974 of the California Code of Regulations, and Pacific Gas and Electric's EMF reduction guidelines.

Verification: At least 30 days prior to start of construction of the transmission line or related structures and facilities, the project owner shall submit to the Compliance Project Manager (CPM) a letter signed by a California registered electrical engineer affirming that the lines will be constructed according to the requirements stated in the condition.

TLSN-2 The project owner shall use a qualified individual to measure the strengths of the electric and magnetic fields from the line at the points of maximum intensity along the candidate routes for which the applicant provided specific estimates. The measurements shall be made before and after energization according to the American National Standard Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) standard procedures. These measurements shall be completed no later than six months after the start of operations.

Verification: The project owner shall file copies of the pre-and post-energization measurements with the CPM within 60 days after completion of the measurements.

TLSN-3 The project owner shall ensure that the right-of-way for each of the candidate routes for the proposed transmission line is kept free of combustible material, as required under the provisions of section 4292 of the Public Resources Code and section 1250 of Title 14 of the California Code of Regulations.

Verification: During the first five (5) years of plant operation, the project owner shall provide a summary of inspection results and any fire prevention activities carried out along the right-of-way and provide such summaries in the Annual Compliance Report on transmission line safety and nuisance-related requirements.

TLSN-4 The project owner shall ensure that all permanent metallic objects within the right-of-way of the chosen route are grounded according to industry standards regardless of ownership.

<u>Verification:</u> At least 30 days before the lines are energized, the project owner shall transmit to the CPM a letter confirming compliance with this condition.

CONCLUSIONS

Since staff does not expect the proposed 230-kV transmission tie-in line to pose an aviation hazard within any of the two candidate routes according to current FAA criteria, we do not consider it necessary to recommend specific location changes on the basis of a potential hazard to area aviation.

The potential for nuisance shocks would be minimized through grounding and other field-reducing measures that would be implemented in keeping with current PG&E guidelines (reflecting standard industry practices). These field-reducing measures would maintain the generated fields within levels not associated with radio-frequency interference or audible noise.

The potential for hazardous shocks would be minimized through compliance with the height and clearance requirements of CPUC's General Order 95. Compliance with Title 14, California Code of Regulations, section 1250, would minimize fire hazards while the use of low-corona line design, together with appropriate corona-minimizing construction practices, would minimize the potential for corona noise and its related interference with radio-frequency communication in the area around the chosen route.

Since electric or magnetic field health effects have neither been established nor ruled out for the proposed HECA and similar transmission lines, the public health significance of any related field exposures cannot be characterized with certainty. The only conclusion to be reached with certainty is that the proposed line's design and operational plan would be adequate to ensure that the generated electric and magnetic fields are managed to an extent the CPUC considers appropriate in light of the available health effects information. The long-term, mostly residential, magnetic exposure of health concern in recent years would be insignificant for the proposed line given the absence of residences along the proposed route. On-site worker or public exposure would be short term and at levels expected for PG&E lines of similar design and current-carrying capacity. Such exposure is well understood and has not been established as posing a significant human health hazard.

Since the proposed project's line would be operated to minimize the health, safety, and nuisance impacts of concern to staff and would be routed in each candidate route through an area with no nearby residences, staff considers the proposed design, maintenance, and construction plan as complying with the applicable LORS. With implementation of the four recommended conditions of certification, any such impacts would be less than significant for either of the two candidate routes.

REFERENCES

EPRI — Electric Power Research Institute 1982. Transmission Line Reference Book: 345 kV and Above.

National Institute of Environmental Health Services 1998. *An Assessment of the Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields*. A Working Group Report. August 1998.

HEI (Hydrogen Energy International, LLC) 2008a. Revised Application for Certification for the Hydrogen Energy California HECA, Volumes I and II. Submitted to the California Energy Commission in November, 2008.

WORKER SAFETY AND FIRE PROTECTION

Geoff Lesh, P.E., Rick Tyler, and Alvin Greenberg, PhD

SUMMARY OF CONCLUSIONS

Staff concludes that if the applicant for the proposed Hydrogen Energy California Project provides project construction safety and health, and project operations and maintenance safety and health programs, as required by conditions of certification **WORKER SAFETY-1,** through **-7**, the project would incorporate sufficient measures to both ensure adequate levels of industrial safety and comply with applicable laws, ordinances, regulations, and standards. These proposed conditions of certification ensure that these programs, proposed by the applicant, will be reviewed by the appropriate agencies before they are implemented. The conditions also require verification that the proposed plans adequately ensure worker safety and fire protection and comply with applicable LORS.

The proposed facility would be located in an area that is currently served by the Kern County Fire Department. In ongoing concurrent siting of other power plant projects (Beacon Solar Power Plant and Ridgecrest Solar Power Plant), both of which are in eastern Kern County, the County has indicated that in general, services provided by the County which include police, fire, and emergency medical services would be impacted by this type of project. Although the Kern County Fire Department has been contacted regarding potential impacts that would be caused by the construction and operation of the Hydrogen Energy California Project, they have responded that there will be impacts, but have not yet provided details of what mitigation they believe will be required. The Kern County Fire Department indicated that they are continuing their discussions with the applicant. Upon consideration of the County's response to these other projects, staff estimates that direct and cumulative impacts would exist if the proposed Hydrogen Energy California Project is built. Therefore, Energy Commission Staff recommends proposed Condition of Certification **WORKER SAFETY-8** as a place holder until the Kern County Fire Department can reach an agreement and/or specifically identify the necessary mitigation.

INTRODUCTION

Worker safety and fire protection are regulated through federal, state, and local laws, ordinances, regulations, and standards (LORS). Industrial workers at the facility both operate equipment and handle hazardous materials daily, and could face hazards resulting in accidents and serious injury. Protection measures are employed to eliminate or reduce these hazards or minimize their risk through special training, protective equipment, and procedural controls.

The purpose of this preliminary staff assessment (PSA) is to assess the worker safety and fire protection measures proposed by the Hydrogen Energy California Project (HECA) applicant and determine whether the applicant has proposed adequate measures to:

- Comply with applicable safety LORS;

- Protect workers during the construction and operation of the facility;
- Protect against fire; and
- Provide adequate emergency response procedures.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

Worker Safety and Fire Protection Table 1
Laws, Ordinances, Regulations, and Standards

Applicable Law	Description
Federal	
29 U.S. Code sections 651 et seq (Occupational Safety and Health Act of 1970)	This Act mandates safety requirements in the workplace, with the purpose of "[assuring] so far as possible every working man and woman in the nation safe and healthful working conditions and to preserve our human resources" (29 USC § 651).
29 CFR sections 1910.1 to 1910.1500 (Occupational Safety and Health Administration Safety and Health Regulations)	These sections define the procedures for promulgating regulations and conducting inspections to implement and enforce safety and health procedures to protect workers, particularly in the industrial sector.
29 CFR sections 1952.170 to 1952.175	These sections provide federal approval of California's plan for enforcement of its own safety and health requirements, in lieu of most of the federal requirements found in 29 CFR §1910.1 to 1910.1500.
State	
8 CCR all applicable sections (Cal/OSHA regulations)	Requires that all employers follow these regulations as they pertain to the work involved. This includes regulations pertaining to safety matters during the construction, commissioning, and operation of power plants, as well as safety around electrical components, fire safety, and hazardous materials usage, storage, and handling.
24 CCR section 3, et seq.	Incorporates the current edition of the International Building Code.
Health and Safety Code sections 25500 to 25541	Requires a Hazardous Materials Business plan detailing emergency response plans for hazardous materials emergencies at a facility.

Local (or locally enforced)	
2007 Edition of California Fire Code and all applicable NFPA standards (24	NFPA standards are incorporated into the California State Fire Code. The fire code contains general provisions for fire safety, including road and building access, water supplies, fire protection and life safety systems, fire-resistive construction, storage of combustible materials, exits and emergency

CCR Part 9)	escapes, and fire alarm systems.
Title 24, California Code of Regulations (24 CCR § 3, et seq.)	The California Building Code is comprised of 11 parts containing building design and construction requirements as they relate to fire, life, and structural safety. It incorporates current editions of the International Building Code, including the electrical, mechanical, energy, and fire codes applicable to the project.
Kern County Zoning Ordinance, Development Standards section 19.80.030.	Contains safety setbacks required by the Kern County Fire Department.

SETTING

Fire support services to the site will be under the jurisdiction of the Kern County Fire Department (KCFD). Station 25 is 7 miles from the project site, located at 100 Mirasol Avenue, Buttonwillow, California, and would be the first responder to HECA with a response time of approximately 7 minutes. Station 21, which includes a ladder company, is approximately 12 miles from the project site, located at 310 10th Street, Taft, California, and would be the second responder to HECA with a response time of approximately 11 minutes. Both stations are continuously staffed with three personnel per shift and have at least one Engine and one Patrol vehicle. All personnel are trained to at least EMT-1 level. (Goodell 2010a).

In Kern County, hazardous materials permits and spills are handled and investigated by KCFD. Kern County firefighters receive specialized training to address emergency responses to industrial hazards, and response would come from the same facilities as for fire services response. If ever needed, a specialized hazardous materials response team would come from 3000 Landco Drive, Bakersfield with a response time of approximately 50 minutes.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Two issues are assessed in **Worker Safety and Fire Protection**:

1. The potential for impacts on the safety of workers during demolition, construction, and operation activities; and

2. Fire prevention/protection, emergency medical response, and hazardous materials spill response during demolition, construction, and operations.

Worker safety is essentially a LORS compliance matter and if all LORS are followed, workers will be adequately protected. Thus, the standard for staff's review and determination of significant impacts on worker health is whether the applicant has demonstrated adequate knowledge of and commitment to implementation of all pertinent and relevant Cal-OSHA standards.

Staff reviews and evaluates the on-site fire-fighting systems proposed by the applicant, as well as the time needed for off-site local fire departments to respond to a fire, medical, or hazardous material emergency at the HECA site. If on-site systems do not follow established codes and industry standards, staff recommends additional measures. Staff reviews local fire department capabilities and response times, and interviews local fire officials to determine if they feel they are adequately staffed, and equipped to respond to the needs of a power plant. Staff then determines, based on information obtained from the applicant and the local fire department, if the presence of the power plant would cause a significant impact on a local fire department. If it does, staff will propose a condition of certification that would require the applicant to mitigate this impact by providing additional resources to the fire department.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Worker Safety

Industrial environments are potentially dangerous during both construction and operation. Workers at the proposed project will be exposed to loud noises, moving equipment, trenches, and confined space entry and egress. Workers may sustain falls, trips, burns, lacerations, and other injuries. They may be exposed to falling equipment or structures, chemical spills, hazardous waste, fires, explosions, and electrical sparks or electrocution. It is important that HECA has well-defined policies and procedures, training, and hazard recognition and control to minimize these hazards and protect workers. If the facility complies with all LORS, workers will be adequately protected from health and safety hazards.

A Safety and Health Program will be prepared by the applicant to minimize worker hazards during construction and operation of the project. “Safety and Health Program,” for staff, refers to measures that will be taken to ensure compliance with the applicable LORS during the construction and operation of the project.

Construction Safety and Health Program

HECA includes the construction and operation of a hybrid power plant that includes a petroleum coke (pet coke) and coal gasification unit with all its associated hazardous chemical separation and fuel handling systems. For the power block, workers will be exposed to hazards typical of construction and operation of a gas-fired combined-cycle facility.

Construction safety orders are published at Title 8 of the California Code of Regulations, section 1502 et seq. These requirements are promulgated by Cal/OSHA and apply to the construction phase of the project. The construction safety and health program will include the following:

- Construction injury and illness prevention program (8 CCR § 1509);
- Construction fire prevention plan (8 CCR § 1920);
- Personal protective equipment program (8 CCR §§ 1514 - 1522); and

- Emergency action program and plan.

Additional programs under General Industry Safety Orders (8 CCR §§ 3200 to 6184), Electrical Safety Orders (8 CCR §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 CCR §§ 450 to 544) will include:

- Electrical safety program;
- Motor vehicle and heavy equipment safety program;
- Forklift operation program;
- Excavation/trenching program;
- Fall protection program;
- Scaffolding/ladder safety program;
- Articulating boom platforms program;
- Crane and material handling program;
- Housekeeping and material handling and storage program;
- Respiratory protection program;
- Employee exposure monitoring program;
- Hand and portable power tool safety program;
- Hearing conservation program;
- Back injury prevention program;
- Hazard communication program;
- Heat and cold stress monitoring and control program;
- Pressure vessel and pipeline safety program;
- Hazardous waste program;
- Hot work safety program;
- Permit-required confined space entry program; and
- Demolition procedure (if applicable).

The Application for Certification (AFC) includes adequate outlines for each of the above programs (HEI 2008c, section 5.7.2.1). Prior to the project's start of construction, detailed programs and plans will be provided pursuant to Condition of Certification **WORKER SAFETY-1**.

Operations and Maintenance Safety and Health Program

Prior to the start-up of HECA, an operations and maintenance safety and health program will be prepared. This program will include the following programs and plans:

- Injury and illness prevention program (8 CCR § 3203);
- Fire prevention program (8 CCR § 3221);

- Personal protective equipment program (8 CCR §§ 3401 to 3411); and
- Emergency action plan (8 CCR § 3220).

In addition, the requirements under General Industry Safety Orders (8 CCR §§ 3200 to 6184), Electrical Safety Orders (8 CCR §§2299 to 2974) and Unfired Pressure Vessel Safety Orders (8 CCR §§ 450 to 544) will apply to this project. Written safety programs for HECA, which the applicant will develop, will ensure compliance with those requirements.

The AFC includes adequate outlines for an injury and illness prevention program, an emergency action plan, a fire prevention program, and a personal protective equipment program (HEI 2008c, section 5.7.2). Prior to operation of HECA, all detailed programs and plans will be provided pursuant to Condition of Certification **WORKER SAFETY-2**.

Safety and Health Program Elements

As mentioned above, the applicant provided the proposed outlines for both a Construction Safety and Health Program and an Operations Safety and Health Program. The measures in these plans are derived from applicable sections of state and federal law. The major items required in both Safety and Health Programs are as follows:

Injury and Illness Prevention Program (IIPP)

The IIPP will include the following components (HEI 2008c , section 5.7.2.3):

- Identify persons with the authority and responsibility for implementing the program;
- Establish the safety and health policy of the plan;
- Define work rules and safe work practices for work activities;
- Establish a system for ensuring that employees comply with safe and healthy work practices;
- Establish a system to facilitate employer-employee communication;
- Develop procedures for identifying and evaluating workplace hazards and establish necessary program(s);
- Establish methods for correcting unhealthy/unsafe conditions in a timely manner;
- Determine and establish training and instruction requirements and programs;
- Specify safety procedures; and
- Provide training and instruction.

Fire Prevention Plan

The California Code of Regulations requires an operations fire prevention plan (8 CCR § 3221). The AFC outlines a proposed fire prevention plan that is acceptable to staff (HEI 2008c, section 5.7.2.9). The plan will include the following:

- Determine general program requirements;

- Determine fire hazard inventory, including ignition sources and mitigation;
- Develop good housekeeping practices and proper materials storage;
- Establish employee alarms and/or communication system(s);
- Provide portable fire extinguishers at appropriate site locations;
- Locate fixed firefighting equipment in suitable areas;
- Specify fire control requirements and procedures;
- Establish proper flammable and combustible liquid storage facilities;
- Identify the location and use of flammable and combustible liquids;
- Provide proper dispensing and determine disposal requirements for flammable liquids;
- Establish and determine training and instruction requirements and programs; and
- Identify contacts for information on plan contents.

Staff proposes that the applicant submit a final fire prevention plan to the California Energy Commission compliance project manager (CPM) for review and approval and to the KCFD for review and comment to satisfy proposed conditions of certification **WORKER SAFETY-1** and **WORKER SAFETY-2**.

Personal Protective Equipment Program

California regulations require personal protective equipment (PPE) and first aid supplies whenever hazards in the environment, or from chemicals or mechanical irritants, could cause injury or impair bodily function through absorption, inhalation, or physical contact (8 CCR sections 3380 to 3400). The HECA operational environment will require PPE (HEI 2008c, section 5.7.2.6).

All safety equipment must meet National Institute of Safety and Health (NIOSH) or American National Standards Institute (ANSI) standards and will carry markings, numbers, or certificates of approval. Respirators must meet NIOSH and Cal/OSHA standards. Each employee must be provided with the following information about protective clothing and equipment:

- Proper use, maintenance, and storage;
- When protective clothing and equipment are used;
- Benefits and limitations; and
- When and how protective clothing and equipment are replaced.

The PPE program ensures that employers comply with applicable requirements for PPE and provides employees with the information and training necessary to protect them from potential hazards in the workplace, and will be required as per proposed Conditions of Certification **WORKER SAFETY-1 and -2**.

Emergency Action Plan

California regulations require an emergency action plan (8 CCR § 3220). The AFC contains a satisfactory outline for an emergency action plan (HEI 2008c, section 5.7.2.8 and Tables 5.7-6 to -7).

The outline lists the following features:

- Establishes emergency procedures for the protection of personnel, equipment, the environment, and materials;
- Identifies fire and emergency reporting procedures;
- Determines response actions for accidents involving personnel and/or property;
- Develops response and reporting requirements for bomb threats;
- Specifies site assembly and emergency evacuation route procedures;
- Defines natural disaster responses (for example, earthquakes, high winds, and flooding);
- Establishes reporting and notification procedures for emergencies (including on-site, off-site, local authorities, and/or state jurisdictions);
- Determines alarm and communication systems needed for specific operations;
- Includes a spill response, prevention, and countermeasure (SPCC) plan;
- Identifies emergency personnel (response team) responsibilities and notification roster;
- Specifies emergency response equipment and strategic locations; and
- Establishes and determines training and instruction requirements and programs.

An emergency action plan will be required as per proposed Conditions of Certification **WORKER SAFETY-1 and -2**

Written Safety Program

In addition to the specific plans listed above, additional LORS called “safe work practices” apply to the project. Both the construction and operations safety programs will address safe work practices in a variety of programs. The components of these programs include, but are not limited to, the programs found under the heading “Construction Safety and Health Program” in this staff assessment.

In addition, the project owner would be required to provide personnel protective equipment and exposure monitoring for workers involved in activities where contaminated soil and/or contaminated groundwater exist, per staff’s proposed Conditions of Certification **WORKER SAFETY-1** and**-2**.

These proposed conditions of certification ensure that workers are properly protected from any hazardous wastes presently at the site.

Safety Training Programs

Employees will be trained in the safe work practices described in the above-referenced safety programs.

Additional Mitigation Measures

Protecting construction workers from injury and disease is one of the greatest challenges today in occupational safety and health. The following facts are reported by NIOSH:

- More than seven million persons work in the construction industry, representing 6 % of the labor force. Approximately 1.5 million of these workers are self-employed;
- Of approximately 600,000 construction companies, 90 % employ fewer than 20 workers. Few have formal safety and health programs;
- From 1980-1993, an average of 1,079 construction workers were killed on the job each year, with more fatal injuries than any other industry;
- Falls caused 3,859 construction worker fatalities, or 25.6 % of the total, between 1980 and 1993;
- 15 % of workers' compensation costs are spent on construction-related injuries;
- Ensuring safety and health in construction is a complex task involving short-term work sites, changing hazards, and multiple operations and crews working in close proximity to one another;
- In 1990, Congress directed NIOSH to conduct research and training to reduce diseases and injury among construction workers in the United States. Under this mandate, NIOSH funds both intramural and extramural research projects.

The hazards associated with the construction industry are well documented. These hazards increase in complexity in the multi-employer worksites typical of large, complex industrial projects like integrated gasification combined-cycle power plants. In order to reduce and/or eliminate these hazards, it has become standard industry practice to hire a construction safety supervisor to ensure a safe and healthful environment for all workers. This has been evident in the audits of power plants recently conducted by the staff. The Federal Occupational Safety and Health Administration (OSHA) has also entered into strategic alliances with several professional and trade organizations to promote and recognize safety professionals trained as construction safety supervisors, construction health and safety officers, and other professional designations. The goal of these partnerships is to encourage construction subcontractors to improve their safety and health performance; to assist them in striving to eliminate the four major construction hazards (falls, electrical, caught in/between, and struck-by hazards) that account for the majority of fatalities and injuries in this industry and have been the focus of targeted OSHA inspections; to prevent serious accidents in the construction industry through implementation of enhanced safety and health programs and increased employee training; and to recognize subcontractors that have exemplary safety and health programs.

There are no OSHA or Cal-OSHA requirements that an employer hire or provide for a construction safety officer. OSHA and Cal-OSHA regulations do, however, require that safety be provided by an employer and the term “Competent Person” appears in many OSHA and Cal-OSHA standards, documents, and directives. A “Competent Person” is defined by OSHA as an individual who, by way of training and/or experience, is knowledgeable of standards, is capable of identifying workplace hazards relating to the specific operations, is designated by the employer, and has authority to take appropriate action. Therefore, in order to meet the intent of the OSHA standard to provide for a safe workplace during power plant construction, staff proposes Condition of Certification **WORKER SAFETY-3,** which would require the applicant/project owner to designate and provide for a project site construction safety supervisor.

As discussed above, the hazards associated with the construction industry are well documented. These hazards increase in complexity in the multi-employer worksites typical of large, complex industrial projects like integrated gasification combined-cycle power plants.

Accidents, fires, and a worker death have occurred at Energy Commission-certified power plants in the recent past because of both the failure to recognize and control safety hazards and the inability to adequately monitor compliance with occupational safety and health regulations. Safety problems have been documented by Energy Commission staff in safety audits, conducted in 2005, at several power plants under construction. The findings of the audit include, but are not limited to, safety oversights like:

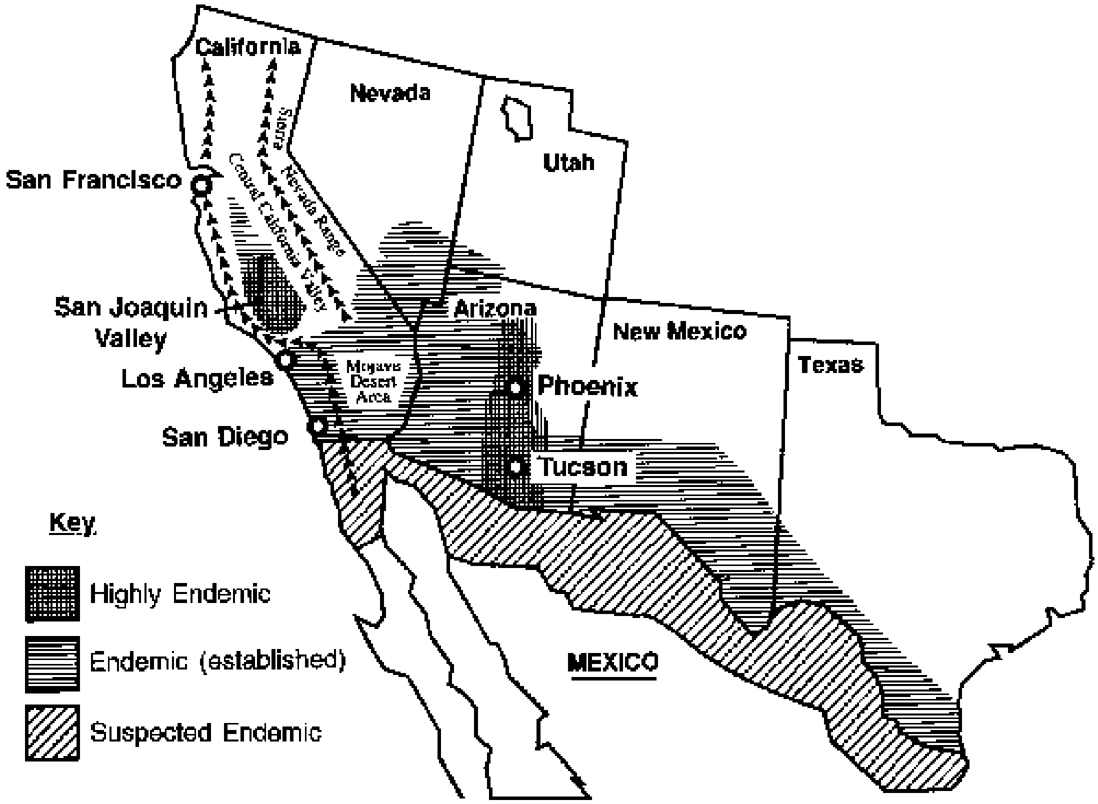
- Lack of posted confined-space warning placards/signs;
- Confusing and/or inadequate electrical and machinery lockout/tagout permitting and procedures;
- Confusing and/or inappropriate procedures for handing over lockout/tagout and confined space permits from the construction team to the commissioning team, and then to operations;
- Dangerous placement of hydraulic elevated platforms under one another;
- Inappropriate placement of fire extinguishers near hot work;
- Dangerous placement of numerous power cords in standing water on the site, increasing the risk of electrocution;
- Inappropriate and unsecure placement of above-ground natural gas pipelines inside the facility, but too close to the perimeter fence; and
- Lack of adequate employee or contractor written training programs that address the proper procedures to follow in the event of the discovery of suspicious packages or objects either onsite or offsite.

In order to reduce and/or eliminate these hazards, it is necessary for the Energy Commission to require a professional Safety Monitor on-site to track compliance with Cal-OSHA regulations and periodically audit safety compliance during construction, commissioning, and the hand-over to the operations staff. These requirements are outlined in Condition of Certification **WORKER SAFETY-4**. A Safety Monitor, hired by the project owner but reporting to the Chief Building Official (CBO) and the Compliance Project Manager (CPM), will serve as an extra set of eyes to ensure that safety procedures and practices are fully implemented during construction at all power plants certified by the Energy Commission. During audits conducted by staff, most site safety professionals welcomed the audit team and actively engaged them in questions about the team's findings and recommendations. These safety professionals recognized that safety requires continuous vigilance and that the presence of an independent audit team provides a "fresh perspective" of the site.

Valley Fever (Coccidioidomycosis)

Coccidioidomycosis or "Valley Fever" (VF) is primarily encountered in southwestern states, particularly in Arizona and California. It is caused by inhaling the spores of the fungus Coccidioides immitis, which are released from the soil during soil disturbance (e.g., during construction activities) or wind erosion. The disease usually affects the lungs and can have potentially severe consequences, especially in at-risk individuals such as the elderly, pregnant women, and people with compromised immune systems. Trenching, excavation, and construction workers are often the most exposed population. Treatment usually includes rest and antifungal medications. No effective vaccine currently exists for Valley Fever. VF is endemic to the San Joaquin valley in California, which presumably gave this disease its common name. Kern County, located at the southern end of San Joaquin valley, is where valley fever occurs most frequently (Valley Fever Vaccine Project of the Americas 2010; KCDPH 2008). Depending on the particular year, either Tulare or Fresno county have the second highest rates of VF.

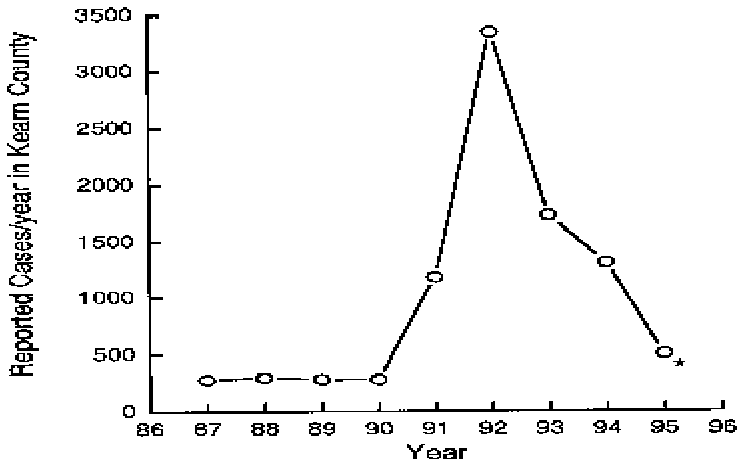
Worker Safety Figure 1. The geographic distribution of coccidioidomycosis*



*Source: CDC 2006, Figure 2

In 1991, 1,200 cases of VF were reported to the California Department of Health Services (CDHS) compared with an annual average of 428 cases per year for the period of 1981 to 1990. In 1992, 4,516 cases were reported in California and 4,137 cases in 1993. 70% of VF cases were reported from Kern County (CDC 1994; Flaherman 2007; CDHS 2010).

Worker Safety Figure 2. Number of coccidioidomycosis cases identified by serologic testing at the Kern County Public Health Laboratory between 1986 and 1996*



*Source: CDC 2006, Figure 4

A 2004 CDC report found that the number of reported cases of coccidioidomycosis in the US increased by 32 % during 2003-2004, with the majority of these cases occurring in California and Arizona. The report attributed these increases to changes in land use, demographics, and climate in endemic areas, although certain cases might be attributable to increased physician awareness and testing (CDC 2006).

According to the CDC Morbidity and Mortality Weekly Report of February 2009, incidences of valley fever have increased steadily in Arizona and California in the past decade. Cases of coccidioidomycosis averaged about 2.5 per 100,000 population annually from 1995 to 2000 and increased to 8.0 per 100,000 population between 2000 and 2006 (incident rates tripled). In 2007 there was a slight drop in cases, but the rate was still the highest it has been since 1995. The report identified Kern County as having the highest incidence rates (150.0 cases per 100,000 population), and non-Hispanic blacks having the highest hospitalization rates (7.5 per 100,000 population). In addition, between the years 2000 and 2006, the number of valley fever related hospitalizations climbed from 1.8 to 4.3 per 100,000 population (611 cases in 2000 to 1,587 cases in 2006) and then decreased to 1,368 cases in 2007 (3.6 per 100,000 population). Overall in California, during 2000-2007, a total of 752 (8.7 %) of the 8,657 persons hospitalized for coccidioidomycosis died (CDC 2009).

A 2007 study published in the Emerging Infectious Diseases journal of the Center for Disease Control and Prevention (CDC), found the frequency of hospitalization for coccidioidomycosis in the entire state of California to be 3.7 per 100,000 residents per year for the period between 1997 and 2002 (see Table one below). There were 417 deaths from VF in California in those years, resulting in a mortality rate of 2. per one million California residents annually. The data shows that Kern County had the highest total number and highest frequency of hospitalizations (Flaherman 2007).

Worker Safety Table 1: Hospitalizations for coccidioidomycosis, California, 1997–2002*

Category	Total hospitalizations	Total person-years (× 10^6)	Frequency of hospitalization**	Frequency of hospitalization for coccidioidal meningitis**
Total	7,457	203.0	3.67	0.657
Year				
1997	1,269	32.5	3.90	0.706
1998	1,144	32.9	3.50	0.706
1999	1,167	33.4	3.5	0.61
2000	1,100	34.0	3.23	0.62
2001	1,291	34.7	3.7	0.58
2002	1,486	35.3	4.2	0.71
Highest incidence counties				
Kern	1,700	3.97	42.8	
Tulare	479	2.21	21.7	
Kings	133	0.77	17.4	
San Luis Obispo	170	1.48	11.5	

*Source: Flaherman 2007
**Per 100,000 residents per year

A 1996 paper that tried to explain the sudden increase in Coccidioidomycosis cases that began in the early 1990's found that the San Joaquin Valley in California has the largest population of C. immitis, which is found to be distributed unevenly in the soil and seems to be concentrated around animal burrows and ancient Indian burial sites. It is usually found 4 to 12 inches below the surface of the soil (CDC 2006). The paper also reported that incidences of coccidioidomycosis vary with the seasons; with highest rates in late summer and early fall when the soil is dry and the crops are harvested. Dust storms are frequently followed by outbreaks of coccidioidomycosis (CDC 2006). A modeling attempt to establish the relationship between fluctuations in VF incident rates and weather conditions in Kern County found that there is only a weak connection between weather and VF cases (weather patterns correlate with up to 4 % of outbreaks). The study concluded that the factors that cause fluctuations in VF cases are not weather-related but rather biological and anthropogenic (i.e. human activities, primarily construction on previously undisturbed soil) (Talamantes 2007).

Data from the Kern County Department of Public Health (KCDPH) on the period between 1995 and 2008 shows that VF cases increased in Kern County during the early 1990's, decreased during the late 1990's, increased again between 2000 and 2005, and have been declining slightly in the last several years. The majority of VF cases are recorded in the Bakersfield area where 50 to 70 % of all Kern County VF cases occur. Delano, Lamont, and Taft have the next highest recorded incidences of VF (KCDPH 2008).

Worker Safety Table 2: Valley Fever Cases In Kern County 1995 – 2008*

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Kern County Cases	523	382	307	328	504	406	994	1055	1281	1540	1578	1081	1229	1128
Rate per 100,000	84.5	61	48.3	51.2	77.1	61	145.7	150.9	177.7	206.9	204.9	135.2	150.4	135.1

*Source: KCDPH 2008, Table 1

Figure 3: VF Cases in Kern County 1995 - 2008*

*Source: KCDPH 2008, Figure 2

During a phone conversation with Dr. Michael MacLean of the Kings County Health Department, he noted that according to his experience and of those who study VF, it is very hard to find the fungus in soil that was previously farmed and irrigated, which greatly reduces the risk of infection resulting from disturbance of farmed lands (MacLean 2009). This does not apply to previously undisturbed lands where excavation, grading, and construction may correlate with increases in VF cases. Dr. MacLean feels that with the current state of knowledge, we can only speculate on the causes and trends influencing VF cases and he does not feel that construction activities are necessarily the cause of VF outbreaks (KCEHS 2009).

Valley Fever is spread through the air. If soil containing the fungus is disturbed by construction, natural disasters, or wind, the fungal spores get into the air where people can breathe in the spores. The disease is not spread from person to person. Occupational or recreational exposure to dust is an important consideration. Agricultural workers, construction workers, or others (such as archeologists) who dig in the soil in the disease-endemic area of the Central Valley are at the highest risk for the disease (CDC 2006; CDHS 2010). The risk for disseminated coccidioidomycosis is much higher among some ethnic groups, particularly African-Americans and Filipinos. In these ethnic groups, the risk for disseminated coccidioidomycosis is tenfold that of the general population (CDC 2006).

A VF website claims that most cases of valley fever do not require treatment. Even though 30-60 % of the population in areas where the disease is highly prevalent - such as in the southern San Joaquin Valley of California - have positive skin tests indicating previous infection, most were unaware of ever having had valley fever ("Valley Fever Vaccine Project of the Americas" 2010).

Worker Safety Table 3: Disease Forms

CATEGORIES	NOTES
Asymptomatic	• Occurs in about 50 % of patients
Acute Symptomatic	• Pulmonary syndrome that combines cough, chest pain, shortness of breath, fever, and fatigue. • Diffuse pneumonia affects immunosuppressed individuals • Skin manifestations include fine papular rash, erythema nodosum, and erythema multiforme • Occasional migratory arthralgias and fever
Chronic Pulmonary	• Affects between 5 to 10 % of infected individuals • Usually presents as pulmonary nodules or peripheral thin-walled cavities
Extrapulmonary/Disseminated Varieties	
Chronic skin disease	• Keratotic and verrucose ulcers or subcutaneous fluctuant abscesses
Joints / Bones	• Severe synovitis and effusion that may affect knees, wrists, feet, ankles, and/or pelvis • Lytic lesions commonly affecting the axial skeleton
Meningeal Disease	• The most feared complication • Presenting with classic meningeal symptoms and signs • Hydrocephalus is a frequent complication
Others	• May affect virtually any organ, including thyroid, GI tract, adrenal glands, genitourinary tract, pericardium, peritoneum

Given the available scientific and medical literature on Valley Fever, it is difficult for staff to assess the potential for VF to impact workers during construction and operation of the proposed project with a reasonable degree of certainty. However, the higher number of cases reported in Kern County indicates that the project site may have an elevated risk for exposure. To minimize potential exposure of workers and also the public to coccidioidomycosis during soil excavation and grading, extensive wetting of the soil prior to and during construction activities should be employed and dust masks should be worn at certain times during these activities. The dust (PM10) control measures found in the Air Quality section of this Staff Assessment should be strictly adhered to in order to adequately reduce the risk of contracting VF to less than significant. Towards that, Commission staff proposes Condition of Certification **WORKER SAFETY-7** which would require that the dust control measures found in proposed Conditions **AQ-SC3** and **AQ-SC4** be supplemented with additional requirements.

Fire Hazards

During construction and operation of the proposed HECA there is the potential for both small fires and major structural fires. Electrical sparks, combustion of fuel oil, hydraulic fluid, mineral oil, insulating fluid at the project power plant switchyard or flammable liquids, explosions, and overheated equipment, may cause small fires. Major structural fires in areas without automatic fire detection and suppression systems are unlikely at power plants. Fires and explosions of natural gas or other flammable gasses or liquids are rare. Compliance with all LORS will be adequate to ensure protection from all fire hazards.

Staff reviewed the information provided in the AFC and contacted the KCFD to determine if available fire protection services and equipment would adequately protect workers, and to further determine the project's impact on fire protection services in the area. To date, the KCFD has responded to staff's questions regarding whether the construction and operation of the HECA project would create direct or cumulative impacts, only to indicate that they expect that there would be impacts, but have not yet indicated what level of mitigation will be needed. Historically, one-time payments needed for mitigation of impacts to local fire departments resulting from new power plant construction has ranged from none to $1.4 million, with annual payments sometimes also required. The level of mitigation required is highly dependent upon the size and land area of the plant, its location and surroundings, the amount and types of fire department resources that are already located nearby, and the specific technologies, hazards, and risks that the power plant would present. The HECA project will rely on both onsite fire protection systems and local fire protection services. The onsite fire protection system provides the first line of defense for small fires. In the event of a major fire, fire support services, including trained firefighters and equipment for a sustained response, would be provided by the KCFD.

Construction

During construction, portable fire extinguishers will be located and maintained throughout the site; safety procedures and training will also be implemented (HEI 2008c, section 5.7.2.1). Station #25 of the KCFD in Buttonwillow, California, will provide fire protection backup for larger fires that cannot be extinguished using the project's portable suppression equipment (Goodell 2010a).

Operation

The information in the AFC indicates that the project intends to meet the fire protection and suppression requirements of the California Fire Code, all applicable recommended NFPA standards (including Standard 850, which addresses fire protection at electric generating plants), and all Cal-OSHA requirements, with one exception (see below). Fire suppression elements in the proposed plant will include both fixed and portable fire extinguishing systems.

In addition to the fixed fire protection system, smoke detectors, flame detectors, high-temperature detectors, appropriate class of service portable extinguishers, and fire hydrants must be located throughout the facility at code-approved intervals. These systems are standard requirements of the fire code and NFPA. Staff has determined that they will ensure adequate fire protection.

The applicant would be required by conditions of certification **WORKER SAFETY-1** and **-2** to provide a final fire protection and prevention program to both staff and the KCFD prior to the construction and operation of the project in order to confirm the adequacy of proposed fire protection measures.

The one exception mentioned above pertains to fire department access to the site. Both the California Fire Code (24 CCR Part 9, chapter 5, section 503.1.2) and the Uniform Fire Code (sections 901 and 902) require that access to the site be reviewed and approved by the fire department. All power plants licensed by the Energy Commission have more than one access point to the power plant site. This is sound fire safety procedure and allows for fire department vehicles and personnel to access the site should the main gate be blocked or emergency personnel want to approach an incident from another side. This access point can be restricted to emergency use only and, if possible, should be equipped with the fire department's preferred system for remote keyless entry. The AFC made no mention of a secondary access to the site for emergency services. Therefore, staff proposes a Condition of Certification **WORKER SAFETY-6** that would require the project owner to provide a second access point to the site for emergency vehicles, and to equip this secondary gate with an acceptable entry system or keypad for fire department personnel to open the gate.

Emergency Medical Services Response

A statewide survey was conducted by staff to determine the frequency of incidents requiring emergency medical services (EMS) and off-site fire-fighters for natural gas-fired power plants in California. The purpose of this analysis was to determine what impact, if any, the HECA power plant might have on local emergency services. Staff concludes that incidents at power plants requiring fire or EMS responses are infrequent and represent an insignificant impact on most local fire departments. However, staff has determined that the potential for both work-related and non-work related heart attacks exists at power plants. In fact, staff's research on the frequency of EMS response to gas-fired power plants shows that many of the responses for cardiac emergencies involved non-work related incidences, including visitors. The need for prompt response within a few minutes is well documented in the medical literature. Staff believes that the quickest medical intervention can only be achieved with the use of an on-site defibrillator often called an Automatic External Defibrillator or AED; the response from an off-site provider would take longer regardless of the provider location. This fact is also well documented and serves as the basis for many private and public locations including airports, factories, and government buildings, all of which maintain on-site cardiac defibrillation devices. Therefore, staff concludes that with the availability of modern cost-effective AED devices, it is proper in a power plant environment to maintain these devices on-site in order to treat cardiac arrythmias resulting from industrial accidents or other non-work related causes. Therefore, an additional condition of certification, **WORKER SAFETY-5**, is proposed so that a portable AED will be located on site, and workers will be trained in its use.

CUMULATIVE IMPACTS AND MITIGATION

Staff reviewed what impacts the construction and operation of HECA could have on the fire and emergency service capabilities of the KCFD. Although the KCFD has not yet responded to staff's questions regarding potential impacts, based on KCFD's response to other power plants proposed for Kern County (Beacon Solar and Ridgecrest Solar) and currently going through the permitting process, staff expects that there will be impacts upon the KCFD due to construction and operation of the proposed HECA project. Staff acknowledges that Kern County has indicated that due to its current budgetary shortfalls, it may not be able to maintain the current level of fire and emergency services readiness. Staff therefore proposes Condition of Certification **WORKER SAFETY-8** that would require the project owner to negotiate and conclude an agreement with Kern County to pay an agreed-to amount to Kern County for the support of the fire department's needs for capital, operations and maintenance.

CONCLUSIONS

Staff concludes that if the applicant for the proposed HECA project provides project construction safety and health and project operations and maintenance safety and health programs, as required by Conditions of Certification **WORKER SAFETY-1**, and **-2**; and fulfills the requirements of Conditions of Certification **WORKER SAFETY-3** through**-8**, HECA would incorporate sufficient measures to ensure adequate levels of industrial safety and comply with applicable LORS. Staff also concludes that the proposed project would not have significant impacts on local fire protection services.

PROPOSED CONDITIONS OF CERTIFICATION

WORKER SAFETY-1 The project owner shall submit to the Compliance Project Manager (CPM) a copy of the Project Construction Safety and Health Program containing the following:

- A Construction Personal Protective Equipment Program;
- A Construction Exposure Monitoring Program;
- A Construction Injury and Illness Prevention Program;
- A Construction Emergency Action Plan; and
- A Construction Fire Prevention Plan.

The Personal Protective Equipment Program, the Exposure Monitoring Program, and the Injury and Illness Prevention Program shall be submitted to the CPM for review and approval concerning compliance of the program with all applicable Safety Orders. The Construction Emergency Action Plan and the Fire Prevention Plan shall be submitted to the Kern County Fire Department for review and comment prior to submittal to the CPM for approval.

Verification: At least thirty (30) days prior to the start of construction, the project owner shall submit to the CPM for review and approval a copy of the Project Construction Safety and Health Program. The project owner shall provide a copy of a letter to the CPM from the Kern County Fire Department stating the Fire Department's comments on the Construction Fire Prevention Plan and Emergency Action Plan.

WORKER SAFETY-2 The project owner shall submit to the CPM a copy of the Project Operations and Maintenance Safety and Health Program containing the following:

- Operation Injury and Illness Prevention Plan;
- An Emergency Action Plan;
- Hazardous Materials Management Program;
- Fire An Prevention Program (8 CCR § 3221); and;
- Personal Protective Equipment Program (8 CCR §§ 3401-3411).

The Operation Injury and Illness Prevention Plan, Emergency Action Plan, and Personal Protective Equipment Program shall be submitted to the CPM for review and approval concerning compliance of the program with all applicable Safety Orders. The Operation Fire Prevention Plan and the Emergency Action Plan shall also be submitted to the Kern County Fire Department for review and comment.

Verification: At least thirty (30) days prior to the start of first-fire or commissioning, the project owner shall submit to the CPM for approval a copy of the Project Operations and Maintenance Safety and Health Program. The project owner shall provide a copy of a letter to the CPM from the Kern County Fire Department stating the Fire Department's comments on the Operations Fire Prevention Plan and Emergency Action Plan.

WORKER SAFETY-3 The project owner shall provide a site Construction Safety Supervisor (CSS) who, by way of training and/or experience, is knowledgeable of power plant construction activities and relevant laws, ordinances, regulations, and standards, is capable of identifying workplace hazards relating to the construction activities, and has authority to take appropriate action to assure compliance and mitigate hazards. The CSS shall:

- Have over-all authority for coordination and implementation of all occupational safety and health practices, policies, and programs;
- Assure that the safety program for the project complies with Cal/OSHA and federal regulations related to power plant projects;

- Assure that all construction and commissioning workers and supervisors receive adequate safety training;
- Complete accident and safety-related incident investigations, emergency response reports for injuries, and inform the CPM of safety-related incidents; and
- Assure that all the plans identified in Worker Safety 1 and 2 are implemented.

Verification: At least thirty (30) days prior to the start of site mobilization, the project owner shall submit to the CPM the name and contact information for the Construction Safety Supervisor (CSS). The contact information of any replacement (CSS) shall be submitted to the CPM within one business day.

The CSS shall submit in the Monthly Compliance Report a monthly safety inspection report to include:

- Record of all employees trained for that month (all records shall be kept on site for the duration of the project);
- Summary report of safety management actions and safety-related incidents that occurred during the month;
- Report of any continuing or unresolved situations and incidents that may pose danger to life or health; and
- Report of accidents and injuries that occurred during the month.

WORKER SAFETY-4 The project owner shall make payments to the Chief Building Official (CBO) for the services of a Safety Monitor based upon a reasonable fee schedule to be negotiated between the project owner and the CBO. Those services shall be in addition to other work performed by the CBO. The Safety Monitor shall be selected by and report directly to the CBO, and will be responsible for verifying that the Construction Safety Supervisor, as required in Worker Safety 3, implements all appropriate Cal/OSHA and Commission safety requirements. The Safety Monitor shall conduct on-site (including linear facilities) safety inspections at intervals necessary to fulfill those responsibilities.

Verification: At least thirty (30) days prior to the start of construction, the project owner shall provide proof of its agreement to fund the Safety Monitor services to the CPM for review and approval.

WORKER SAFETY-5 The project owner shall ensure that a portable automatic external defibrillator (AED) is located on site during construction and operations and shall implement a program to ensure that workers are properly trained in its use and that the equipment is properly maintained and functioning at all times. During construction and commissioning, the following persons shall be trained in its use and shall be on-site whenever the workers that they supervise are on-site: the Construction Project Manager or delegate, the Construction Safety Supervisor or delegate, and all shift foremen. During operations, all power plant employees shall be trained in its use. The training program shall be submitted to the CPM for review and approval.

Verification: At least thirty (30) days prior to the start of site mobilization the project owner shall submit to the CPM proof that a portable AED exists on site and a copy of the training and maintenance program for review and approval.

WORKER SAFETY-6 The project owner shall identify and provide a second access point for emergency personnel to enter the site. This access point and the method of gate operation shall be submitted to the Kern County Fire Department for review and comment and to the CPM for review and approval.

Verification: At least sixty (60) days prior to the start of site mobilization, the project owner shall submit to the Kern County Fire Department and the CPM preliminary plans showing the location of a second access point to the site and a description of how the gate will be opened by the fire department. At least thirty (30) days prior to the start of site mobilization, the project owner shall submit final plans to the CPM review and approval. The final plan submittal shall also include a letter containing comments from the Kern County Fire Department or a statement that no comments were received.

WORKER SAFETY-7 The project owner shall develop and implement an enhanced Dust Control Plan that includes the requirements described in **AQ-SC3** and additionally requires:

i) site worker use of dust masks (NIOSH N-95 or better) whenever visible dust is present;

ii) site monitoring for the presence of Coccidioides immitis in soil before site mobilization and monthly thereafter; and

iii) Implementation of enhanced dust control methods (increased frequency of watering, use of dust suppression chemicals, etc. consistent with **AQ-SC4**) immediately whenever visible dust comes from or onto the site.

After three consecutive months of not finding significant soil levels of Coccidioides immitis, the project owner may ask the CPM to re-evaluate and revise this testing requirement.

Verification: At least 60 days prior to the commencement of site mobilization, the enhanced Dust Control Plan shall be provided to the CPM for review and approval.

WORKER SAFETY-8 The project owner shall:

Reach an agreement, either individually or in conjunction with a power generation industry association or group that negotiates on behalf of its members, with the Kern County Fire Department (KCFD) regarding funding of its project-related share of capital and operating costs to build and operate new fire protection/response infrastructure and provide appropriate equipment as mitigation of project-related impacts on fire protection services within the jurisdiction.

Verification: At least thirty (30) days prior to the start of site mobilization, the project owner shall provide to the CPM:

A copy of the individual agreement with the KCFD or, if the owner joins a power generation industry association, a copy of the bylaws and group's agreement/contract with the KCFD.

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ENGINEERING ASSESSMENT

FACILITY DESIGN

Erin Bright

SUMMARY OF CONCLUSIONS

The California Energy Commission staff concludes that the design, construction, and eventual closure of the project and its linear facilities would likely comply with applicable engineering laws, ordinances, regulations and standards. The proposed conditions of certification, below, would ensure compliance with these laws, ordinances, regulations and standards.

INTRODUCTION

Facility design encompasses the civil, structural, mechanical, and electrical engineering design of the Hydrogen Energy California (HECA) Project. The purpose of this analysis is to:

- Verify that the laws, ordinances, regulations and standards (LORS) that apply to the engineering design and construction of the project have been identified;
- Verify that both the project and its ancillary facilities are sufficiently described, including proposed design criteria and analysis methods, in order to provide reasonable assurance that the project will be designed and constructed in accordance with all applicable engineering LORS, in a manner that also ensures the public health and safety;
- Determine whether special design features should be considered during final design to address conditions unique to the site which could influence public health and safety; and
- Describe the design review and construction inspection process and establish the conditions of certification used to monitor and ensure compliance with the engineering LORS, in addition to any special design requirements.

Subjects discussed in this analysis include:

- Identification of the engineering LORS that apply to facility design;
- Evaluation of the applicant’s proposed design criteria, including identification of criteria essential to public health and safety;
- Proposed modifications and additions to the application for certification (AFC) necessary for compliance with applicable engineering LORS; and
- Conditions of certification proposed by staff to ensure that the project will be designed and constructed to ensure public health and safety and comply with all applicable engineering LORS.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

Lists of LORS applicable to each engineering discipline (civil, structural, mechanical, and electrical) are described in the AFC (HEI 2009c, AFC Appendix B). Key LORS are listed in **Facility Design Table 1,** below:

FACILITY DESIGN Table 1
Key Engineering Laws, Ordinances, Regulations and Standards (LORS)

Applicable LORS	Description
Federal	Title 29 Code of Federal Regulations (CFR), Part 1910, Occupational Safety and Health standards
State	2007 (or the latest edition in effect) California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations)
Local	Kern County regulations and ordinances
General	American National Standards Institute (ANSI) American Society of Mechanical Engineers (ASME) American Welding Society (AWS) American Society for Testing and Materials (ASTM)

SETTING

HECA would be built on an approximately 473-acre site located in Kern County. For more information on the site and its related project description, please see the **Project Description** section of this document. Additional engineering design details are contained in the AFC, Appendix B (HEI 2009c).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

The purpose of this analysis is to ensure that the project would be built to applicable engineering codes and ensure public health and safety. This analysis further verifies that applicable engineering LORS have been identified and that the project and its ancillary facilities have been described in adequate detail. It also evaluates the applicant's proposed design criteria, describes the design review and construction inspection process, and establishes conditions of certification that would monitor and ensure compliance with engineering LORS and any other special design requirements. These conditions allow both the California Energy Commission (Energy Commission) compliance project manager (CPM) and the applicant to adopt a compliance monitoring program that will verify compliance with these LORS.

SITE PREPARATION AND DEVELOPMENT

Staff has evaluated the proposed design criteria for grading, flood protection, erosion control, site drainage, and site access, in addition to the criteria for designing and constructing linear support facilities such as natural gas and electric transmission interconnections. The applicant proposes the use of accepted industry standards (see

HEI 2009c, Appendix B, for a representative list of applicable industry standards), design practices, and construction methods in preparing and developing the site. Staff concludes that this project, including its linear facilities, would most likely comply with all applicable site preparation LORS, and proposes conditions of certification (see below and the **Geology and Paleontology** section of this document) to ensure that compliance.

MAJOR STRUCTURES, SYSTEMS, AND EQUIPMENT

Major structures, systems, and equipment are structures and their associated components or equipment that are necessary for power production, costly or time consuming to repair or replace, are used for the storage, containment, or handling of hazardous or toxic materials, or could become potential health and safety hazards if not constructed according to applicable engineering LORS.

HECA will be designed and constructed to the 2007 California Building Standards Code (CBSC), also known as Title 24, California Code of Regulations, which encompasses the California Building Code (CBC), California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and other applicable codes and standards in effect when the design and construction of the project actually begin. If the initial designs are submitted to the chief building official (CBO) for review and approval after the update to the 2007 CBSC takes effect, the 2007 CBSC provisions shall be replaced with the updated provisions.

Certain structures in a power plant may be required, under the CBC, to undergo dynamic lateral force (structural) analysis; others may be designed using the simpler static analysis procedure. In order to ensure that structures are analyzed according to their appropriate lateral force procedure, staff has included condition of certification **STRUC-1**, below, which, in part, requires the project CBO's review and approval of the owner's proposed lateral force procedures before construction begins.

PROJECT QUALITY PROCEDURES

The applicant describes a quality program intended to inspire confidence that its systems and components will be designed, fabricated, stored, transported, installed, and tested in accordance with all appropriate power plant technical codes and standards (HEI 2009c, AFC § 2.8, Appendix B). Compliance with design requirements will be verified through specific inspections and audits. Implementation of this quality assurance/quality control (QA/QC) program will ensure that HECA is actually designed, procured, fabricated, and installed as described in this analysis.

COMPLIANCE MONITORING

Under Section 104.2 of the CBC, the CBO is authorized and directed to enforce all provisions of the CBC. The Energy Commission itself serves as the building official, and has the responsibility to enforce the code, for all of the energy facilities it certifies. In addition, the Energy Commission has the power to interpret the CBC and adopt and enforce both rules and supplemental regulations that clarify application of the CBC's provisions.

The Energy Commission's design review and construction inspection process conforms to CBC requirements and ensures that all facility design conditions of certification are met. As provided by Section 104.2.2 of the CBC, the Energy Commission appoints experts to perform design review and construction inspections and act as delegate CBOs on behalf of the Energy Commission. These delegates may include the local building official and/or independent consultants hired to provide technical expertise that is not provided by the local official alone. The applicant, through permit fees provided by the CBC, pays the cost of these reviews and inspections. While building permits in addition to Energy Commission certification are not required for this project, the applicant pays in lieu of CBC permit fees to cover the costs of these reviews and inspections.

Engineering and compliance staff will invite Kern County or a third-party engineering consultant to act as CBO for this project. When an entity has been assigned CBO duties, Energy Commission staff will complete a memorandum of understanding (MOU) with that entity to outline both its roles and responsibilities and those of its subcontractors and delegates.

Staff has developed proposed conditions of certification to ensure for protection of public health and safety and compliance with engineering design LORS. Some of these conditions address the roles, responsibilities, and qualifications of the engineers who will design and build the proposed project (conditions of certification **GEN-1** through **GEN-8**). These engineers must be registered in California and sign and stamp every submittal of design plans, calculations, and specifications submitted to the CBO. These conditions require that every element of the project's construction (subject to CBO review and approval) be approved by the CBO before it is performed. They also require that qualified special inspectors perform or oversee special inspections required by all applicable LORS.

While the Energy Commission and delegate CBO have the authority to allow some flexibility in scheduling construction activities, these conditions are written so that no element of construction (of permanent facilities subject to CBO review and approval) which could be difficult to reverse or correct can proceed without prior CBO approval. Elements of construction that are not difficult to reverse may proceed without approval of the plans. The applicant bears the responsibility to fully modify construction elements in order to comply with all design changes resulting from the CBO's subsequent plan review and approval process.

FACILITY CLOSURE

The removal of a facility from service (decommissioning) when it reaches the end of its useful life ranges from "mothballing," to the removal of all equipment and appurtenant facilities and subsequent restoration of the site. Future conditions that could affect decommissioning are largely unknown at this time.

In order to ensure that decommissioning will be completed in a manner that is environmentally sound, safe, and protects the public health and safety, the applicant shall submit a decommissioning plan to the Energy Commission for review and approval before the project's decommissioning begins. The plan shall include a discussion of:

- Proposed decommissioning activities for the project and all appurtenant facilities that were constructed as part of the project;
- All applicable LORS, local/regional plans, and proof of adherence to those applicable LORS and local/regional plans;
- The activities necessary to restore the site if the plan requires removal of all equipment and appurtenant facilities; and
- Decommissioning alternatives other than complete site restoration.

Satisfying the above requirements should serve as adequate protection, even in the unlikely event that the project is abandoned. Staff has proposed general conditions (see **General Conditions**) to ensure that these measures are included in the Facility Closure Plan.

CONCLUSIONS AND RECOMMENDATIONS

1. The laws, ordinances, regulations and standards (LORS) identified in the AFC and supporting documents directly apply to the project.

2. Staff has evaluated the proposed engineering LORS, design criteria, and design methods in the record, and concludes that the design, construction, and eventual closure of the project will likely comply with applicable engineering LORS.

3. The proposed conditions of certification will ensure that HECA is designed and constructed in accordance with applicable engineering LORS. This will be accomplished through design review, plan checking, and field inspections that will be performed by the CBO or other Energy Commission delegate. Staff will audit the CBO to ensure satisfactory performance.

4. Though future conditions that could affect decommissioning are largely unknown at this time, it can reasonably be concluded that if, the project owner submits a decommissioning plan as required in the **General Conditions** portion of this document prior to decommissioning, decommissioning procedures will comply with all applicable engineering LORS.

Energy Commission staff recommends that:

1. The proposed conditions of certification be adopted to ensure that the project is designed and constructed in a manner that protects the public health and safety and complies with all applicable engineering LORS;

2. The project be designed and built to the 2007 CBSC (or successor standards, if in effect when initial project engineering designs are submitted for review); and

3. The CBO reviews the final designs, checks plans, and performs field inspections during construction. Energy Commission staff shall audit and monitor the CBO to ensure satisfactory performance.

CONDITIONS OF CERTIFICATION

GEN-1 The project owner shall design, construct, and inspect the project in accordance with the 2007 California Building Standards Code (CBSC), also known as Title 24, California Code of Regulations, which encompasses the California Building Code (CBC), California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and all other applicable engineering LORS in effect at the time initial design plans are submitted to the CBO for review and approval (the CBSC in effect is the edition that has been adopted by the California Building Standards Commission and published at least 180 days previously). The project owner shall ensure that all the provisions of the above applicable codes are enforced during the construction, addition, alteration, moving, demolition, repair, or maintenance of the completed facility. All transmission facilities (lines, switchyards, switching stations and substations) are covered in the conditions of certification in the **Transmission System Engineering** section of this document.

In the event that the initial engineering designs are submitted to the CBO when the successor to the 2007 CBSC is in effect, the 2007 CBSC provisions shall be replaced with the applicable successor provisions. Where, in any specific case, different sections of the code specify different materials, methods of construction or other requirements, the most restrictive shall govern. Where there is a conflict between a general requirement and a specific requirement, the specific requirement shall govern.

The project owner shall ensure that all contracts with contractors, subcontractors, and suppliers clearly specify that all work performed and materials supplied comply with the codes listed above.

Verification: Within 30 days following receipt of the certificate of occupancy, the project owner shall submit to the CPM a statement of verification, signed by the responsible design engineer, attesting that all designs, construction, installation, and inspection requirements of the applicable LORS and the Energy Commission’s decision have been met in the area of facility design. The project owner shall provide the CPM a copy of the certificate of occupancy within 30 days of receipt from the CBO.

Once the certificate of occupancy has been issued, the project owner shall inform the CPM at least 30 days prior to any construction, addition, alteration, moving, demolition, repair, or maintenance to be performed on any portion(s) of the completed facility that requires CBO approval for compliance with the above codes. The CPM will then determine if the CBO needs to approve the work.

GEN-2 Before submitting the initial engineering designs for CBO review, the project owner shall furnish the CPM and the CBO with a schedule of facility design submittals, and master drawings and master specifications list. The master drawings and master specifications list shall contain a list of proposed submittal packages of designs, calculations, and specifications for major structures, systems, and equipment. Major structures, systems, and equipment are structures and their associated components or equipment that are necessary for power production, costly or time consuming to repair or replace, are used for the storage, containment, or handling of hazardous or toxic materials, or could become potential health and safety hazards if not constructed according to applicable engineering LORS. The schedule shall contain the date of each submittal to the CBO. To facilitate audits by Energy Commission staff, the project owner shall provide specific packages to the CPM upon request.

Verification: At least 60 days (or a project owner- and CBO-approved alternative time frame) prior to the start of rough grading, the project owner shall submit to the CBO and to the CPM the schedule, and the master drawings and master specifications list of documents to be submitted to the CBO for review and approval. These documents shall be the pertinent design documents for the major structures, systems, and equipment defined above in Condition of Certification **GEN-2**. Major structures and equipment shall be added to or deleted from the list only with CPM approval. The project owner shall provide schedule updates in the monthly compliance report.

GEN-3 The project owner shall make payments to the CBO for design review, plan checks, and construction inspections, based upon a reasonable fee schedule to be negotiated between the project owner and the CBO. These fees may be consistent with the fees listed in the 2007 CBC, adjusted for inflation and other appropriate adjustments; may be based on the value of the facilities reviewed; may be based on hourly rates; or may be otherwise agreed upon by the project owner and the CBO.

Verification: The project owner shall make the required payments to the CBO in accordance with the agreement between the project owner and the CBO. The project owner shall send a copy of the CBO's receipt of payment to the CPM in the next monthly compliance report indicating that applicable fees have been paid.

GEN-4 Prior to the start of rough grading, the project owner shall assign a California-registered architect, or a structural or civil engineer, as the resident engineer (RE) in charge of the project. All transmission facilities (lines, switchyards, switching stations, and substations) are addressed in the conditions of certification in the **Transmission System Engineering** section of this document.

The RE may delegate responsibility for portions of the project to other registered engineers. Registered mechanical and electrical engineers may be delegated responsibility for mechanical and electrical portions of the project, respectively. A project may be divided into parts, provided that each part is clearly defined as a distinct unit. Separate assignments of general responsibility may be made for each designated part.

The RE shall:

1. Monitor progress of construction work requiring CBO design review and inspection to ensure compliance with LORS;
2. Ensure that construction of all facilities subject to CBO design review and inspection conforms in every material respect to applicable LORS, these conditions of certification, approved plans, and specifications;
3. Prepare documents to initiate changes in approved drawings and specifications when either directed by the project owner or as required by the conditions of the project;
4. Be responsible for providing project inspectors and testing agencies with complete and up-to-date sets of stamped drawings, plans, specifications, and any other required documents;
5. Be responsible for the timely submittal of construction progress reports to the CBO from the project inspectors, the contractor, and other engineers who have been delegated responsibility for portions of the project; and
6. Be responsible for notifying the CBO of corrective action or the disposition of items noted on laboratory reports or other tests when they do not conform to approved plans and specifications.

The resident engineer (or his delegate) must be located at the project site, or be available at the project site within a reasonable period of time, during any hours in which construction takes place.

The RE shall have the authority to halt construction and to require changes or remedial work if the work does not meet requirements.

If the RE or the delegated engineers are reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the resume and registration number of the RE and any other delegated engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the RE and other delegated engineer(s) within five days of the approval.

If the RE or the delegated engineer(s) is subsequently reassigned or replaced, the project owner has five days to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-5 Prior to the start of rough grading, the project owner shall assign at least one of each of the following California registered engineers to the project: a civil engineer; a soils, geotechnical, or civil engineer experienced and knowledgeable in the practice of soils engineering; and an engineering geologist. Prior to the start of construction, the project owner shall assign at least one of each of the following California registered engineers to the project: a design engineer who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; a mechanical engineer; and an electrical engineer. (California Business and Professions Code section 6704 et seq., and sections 6730, 6731 and 6736 require state registration to practice as a civil engineer or structural engineer in California). All transmission facilities (lines, switchyards, switching stations, and substations) are handled in the conditions of certification in the **Transmission System Engineering** section of this document.

The tasks performed by the civil, mechanical, electrical, or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (for example, proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer.

The project owner shall submit, to the CBO for review and approval, the names, qualifications, and registration numbers of all responsible engineers assigned to the project.

If any one of the designated responsible engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned responsible engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

A. The civil engineer shall:

1. Review the foundation investigations, geotechnical, or soils reports prepared by the soils engineer, the geotechnical engineer, or by a civil engineer experienced and knowledgeable in the practice of soils engineering;

2. Design (or be responsible for the design of), stamp, and sign all plans, calculations, and specifications for proposed site work, civil works, and related facilities requiring design review and inspection by the CBO. At a minimum, these include: grading, site preparation, excavation, compaction, construction of secondary containment, foundations, erosion and sedimentation control structures, drainage facilities, underground utilities, culverts, site access roads and sanitary sewer systems; and

3. Provide consultation to the RE during the construction phase of the project and recommend changes in the design of the civil works facilities and changes to the construction procedures.

B. The soils engineer, geotechnical engineer, or civil engineer experienced and knowledgeable in the practice of soils engineering, shall:

1. Review all the engineering geology reports;

2. Prepare the foundation investigations, geotechnical, or soils reports containing field exploration reports, laboratory tests, and engineering analysis detailing the nature and extent of the soils that could be susceptible to liquefaction, rapid settlement or collapse when saturated under load;

3. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with requirements set forth in the 2007 CBC (depending on the site conditions, this may be the responsibility of either the soils engineer, the engineering geologist, or both); and

4. Recommend field changes to the civil engineer and RE.

This engineer shall be authorized to halt earthwork and to require changes if site conditions are unsafe or do not conform to the predicted conditions used as the basis for design of earthwork or foundations.

C. The engineering geologist shall:

1. Review all the engineering geology reports and prepare a final soils grading report; and

2. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 2007 CBC (depending on the site conditions, this may be the responsibility of either the soils engineer, the engineering geologist, or both).

D. The design engineer shall:

1. Be directly responsible for the design of the proposed structures and equipment supports;

2. Provide consultation to the RE during design and construction of the project;

3. Monitor construction progress to ensure compliance with engineering LORS;

4. Evaluate and recommend necessary changes in design; and

5. Prepare and sign all major building plans, specifications, and calculations.

E. The mechanical engineer shall be responsible for, and sign and stamp a statement with, each mechanical submittal to the CBO, stating that the proposed final design plans, specifications, and calculations conform to all of the mechanical engineering design requirements set forth in the Energy Commission's decision.

F. The electrical engineer shall:

1. Be responsible for the electrical design of the project; and

2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible civil engineer, soils (geotechnical) engineer and engineering geologist assigned to the project.

At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of construction, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible design engineer, mechanical engineer, and electrical engineer assigned to the project.

The project owner shall notify the CPM of the CBO's approvals of the responsible engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.

GEN-6 Prior to the start of an activity requiring special inspection, including prefabricated assemblies, the project owner shall assign to the project, qualified and certified special inspector(s) who shall be responsible for the special inspections required by the 2007 CBC. All transmission facilities (lines, switchyards, switching stations, and substations) are handled in conditions of certification in the **Transmission System Engineering** section of this document.

A certified weld inspector, certified by the American Welding Society (AWS), and/or American Society of Mechanical Engineers (ASME) as applicable, shall inspect welding performed on-site requiring special inspection (including structural, piping, tanks and pressure vessels).

The special inspector shall:

1. Be a qualified person who shall demonstrate competence, to the satisfaction of the CBO, for inspection of the particular type of construction requiring special or continuous inspection;

2. Inspect the work assigned for conformance with the approved design drawings and specifications;

3. Furnish inspection reports to the CBO and RE. All discrepancies shall be brought to the immediate attention of the RE for correction, then, if uncorrected, to the CBO and the CPM for corrective action; and

4. Submit a final signed report to the RE, CBO, and CPM, stating whether the work requiring special inspection was, to the best of the inspector's knowledge, in conformance with the approved plans, specifications, and other provisions of the applicable edition of the CBC.

<u>Verification:</u> At least 15 days (or project owner- and CBO-approved alternative time frame) prior to the start of an activity requiring special inspection, the project owner shall submit to the CBO for review and approval, with a copy to the CPM, the name(s) and qualifications of the certified weld inspector(s), or other certified special inspector(s) assigned to the project to perform one or more of the duties set forth above. The project owner shall also submit to the CPM a copy of the CBO's approval of the qualifications of all special inspectors in the next monthly compliance report.

If the special inspector is subsequently reassigned or replaced, the project owner has five days in which to submit the name and qualifications of the newly assigned special inspector to the CBO for approval. The project owner shall notify the CPM of the CBO's approval of the newly assigned inspector within five days of the approval.

GEN-7 If any discrepancy in design and/or construction is discovered in any engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend required corrective actions. The discrepancy documentation shall be submitted to the CBO for review and approval. The discrepancy documentation shall reference this condition of certification and, if appropriate, applicable sections of the CBC and/or other LORS.

<u>Verification:</u> The project owner shall transmit a copy of the CBO's approval of any corrective action taken to resolve a discrepancy to the CPM in the next monthly compliance report. If any corrective action is disapproved, the project owner shall advise the CPM, within five days, of the reason for disapproval and the revised corrective action to obtain CBO's approval.

GEN-8 The project owner shall obtain the CBO's final approval of all completed work that has undergone CBO design review and approval. The project owner shall request the CBO to inspect the completed structure and review the submitted documents. The project owner shall notify the CPM after obtaining the CBO's final approval. The project owner shall retain one set of approved engineering plans, specifications, and calculations (including all approved changes) at the project site or at another accessible location during the operating life of the project. Electronic copies of the approved plans, specifications, calculations, and marked-up as-builts shall be provided to the CBO for retention by the CPM.

Verification: Within 15 days of the completion of any work, the project owner shall submit to the CBO, with a copy to the CPM, in the next monthly compliance report, (a) a written notice that the completed work is ready for final inspection, and (b) a signed statement that the work conforms to the final approved plans. After storing the final approved engineering plans, specifications, and calculations described above, the project owner shall submit to the CPM a letter stating both that the above documents have been stored and the storage location of those documents.

Within 90 days of the completion of construction, the project owner shall provide to the CBO three sets of electronic copies of the above documents at the project owner's expense. These are to be provided in the form of "read only" (Adobe .pdf 6.0) files, with restricted (password-protected) printing privileges, on archive quality compact discs.

CIVIL-1 The project owner shall submit to the CBO for review and approval the following:

1. Design of the proposed drainage structures and the grading plan;
2. An erosion and sedimentation control plan;
3. Related calculations and specifications, signed and stamped by the responsible civil engineer; and
4. Soils, geotechnical, or foundation investigations reports required by the 2007 CBC.

Verification: At least 15 days (or project owner- and CBO-approved alternative time frame) prior to the start of site grading the project owner shall submit the documents described above to the CBO for design review and approval. In the next monthly compliance report following the CBO's approval, the project owner shall submit a written statement certifying that the documents have been approved by the CBO.

CIVIL-2 The resident engineer shall, if appropriate, stop all earthwork and construction in the affected areas when the responsible soils engineer, geotechnical engineer, or the civil engineer experienced and knowledgeable in the practice of soils engineering identifies unforeseen adverse soil or geologic conditions. The project owner shall submit modified plans, specifications, and calculations to the CBO based on these new conditions. The project owner shall obtain approval from the CBO before resuming earthwork and construction in the affected area.

Verification: The project owner shall notify the CPM within 24 hours, when earthwork and construction is stopped as a result of unforeseen adverse geologic/soil conditions. Within 24 hours of the CBO's approval to resume earthwork and construction in the affected areas, the project owner shall provide to the CPM a copy of the CBO's approval.

CIVIL-3 The project owner shall perform inspections in accordance with the 2007 CBC. All plant site-grading operations, for which a grading permit is required, shall be subject to inspection by the CBO.

If, in the course of inspection, it is discovered that the work is not being performed in accordance with the approved plans, the discrepancies shall be reported immediately to the resident engineer, the CBO, and the CPM. The project owner shall prepare a written report, with copies to the CBO and the CPM, detailing all discrepancies, non-compliance items, and the proposed corrective action.

Verification: Within five days of the discovery of any discrepancies, the resident engineer shall transmit to the CBO and the CPM a non-conformance report (NCR), and the proposed corrective action for review and approval. Within five days of resolution of the NCR, the project owner shall submit the details of the corrective action to the CBO and the CPM. A list of NCRs, for the reporting month, shall also be included in the following monthly compliance report.

CIVIL-4 After completion of finished grading and erosion and sedimentation control and drainage work, the project owner shall obtain the CBO's approval of the final grading plans (including final changes) for the erosion and sedimentation control work. The civil engineer shall state that the work within his/her area of responsibility was done in accordance with the final approved plans.

Verification: Within 30 days (or project owner- and CBO-approved alternative time frame) of the completion of the erosion and sediment control mitigation and drainage work, the project owner shall submit to the CBO, for review and approval, the final grading plans (including final changes) and the responsible civil engineer's signed statement that the installation of the facilities and all erosion control measures were completed in accordance with the final approved combined grading plans, and that the facilities are adequate for their intended purposes, along with a copy of the transmittal letter to the CPM. The project owner shall submit a copy of the CBO's approval to the CPM in the next monthly compliance report.

STRUC-1 Prior to the start of any increment of construction, the project owner shall submit plans, calculations and other supporting documentation to the CBO for design review and acceptance for all project structures and equipment identified in the CBO-approved master drawing and master specifications lists. The design plans and calculations shall include the lateral force procedures and details as well as vertical calculations.

Construction of any structure or component shall not begin until the CBO has approved the lateral force procedures to be employed in designing that structure or component.

The project owner shall:

1. Obtain approval from the CBO of lateral force procedures proposed for project structures;

2. Obtain approval from the CBO for the final design plans, specifications, calculations, soils reports, and applicable quality control procedures. If there are conflicting requirements, the more stringent shall govern (for example, highest loads, or lowest allowable stresses shall govern). All plans, calculations, and specifications for foundations that support structures shall be filed concurrently with the structure plans, calculations, and specifications;

3. Submit to the CBO the required number of copies of the structural plans, specifications, calculations, and other required documents of the designated major structures prior to the start of on-site fabrication and installation of each structure, equipment support, or foundation;

4. Ensure that the final plans, calculations, and specifications clearly reflect the inclusion of approved criteria, assumptions, and methods used to develop the design. The final designs, plans, calculations, and specifications shall be signed and stamped by the responsible design engineer; and

5. Submit to the CBO the responsible design engineer's signed statement that the final design plans conform to applicable LORS.

Verification: At least 60 days (or project owner- and CBO-approved alternative time frame) prior to the start of any increment of construction of any structure or component listed in the CBO-approved master drawing and master specifications list, the project owner shall submit to the CBO the above final design plans, specifications and calculations, with a copy of the transmittal letter to the CPM.

The project owner shall submit to the CPM, in the next monthly compliance report, a copy of a statement from the CBO that the proposed structural plans, specifications, and calculations have been approved and comply with the requirements set forth in applicable engineering LORS.

STRUC-2 The project owner shall submit to the CBO the required number of sets of the following documents related to work that has undergone CBO design review and approval:

1. Concrete cylinder strength test reports (including date of testing, date sample taken, design concrete strength, tested cylinder strength, age of test, type and size of sample, location and quantity of concrete placement from which sample was taken, and mix design designation and parameters);

2. Concrete pour sign-off sheets;

3. Bolt torque inspection reports (including location of test, date, bolt size, and recorded torques);

4. Field weld inspection reports (including type of weld, location of weld, inspection of non-destructive testing (NDT) procedure and results, welder qualifications, certifications, qualified procedure description or number (ref: AWS); and

5. Reports covering other structural activities requiring special inspections shall be in accordance with the 2007 CBC.

Verification: If a discrepancy is discovered in any of the above data, the project owner shall, within five days, prepare and submit an NCR describing the nature of the discrepancies and the proposed corrective action to the CBO, with a copy of the transmittal letter to the CPM. The NCR shall reference the condition(s) of certification and the applicable CBC chapter and section. Within five days of resolution of the NCR, the project owner shall submit a copy of the corrective action to the CBO and the CPM.

The project owner shall transmit a copy of the CBO's approval or disapproval of the corrective action to the CPM within 15 days. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action to obtain CBO's approval.

STRUC-3 The project owner shall submit to the CBO design changes to the final plans required by the 2007 CBC, including the revised drawings, specifications, calculations, and a complete description of, and supporting rationale for, the proposed changes, and shall give to the CBO prior notice of the intended filing.

Verification: On a schedule suitable to the CBO, the project owner shall notify the CBO of the intended filing of design changes, and shall submit the required number of sets of revised drawings and the required number of copies of the other above-mentioned documents to the CBO, with a copy of the transmittal letter to the CPM. The project owner shall notify the CPM, via the monthly compliance report, when the CBO has approved the revised plans.

STRUC-4 Tanks and vessels containing quantities of toxic or hazardous materials exceeding amounts specified in the 2007 CBC shall, at a minimum, be designed to comply with the requirements of that chapter.

Verification: At least 30 days (or project owner- and CBO-approved alternate time frame) prior to the start of installation of the tanks or vessels containing the above specified quantities of toxic or hazardous materials, the project owner shall submit to the CBO for design review and approval final design plans, specifications, and calculations, including a copy of the signed and stamped engineer's certification.

The project owner shall send copies of the CBO approvals of plan checks to the CPM in the following monthly compliance report. The project owner shall also transmit a copy of the CBO's inspection approvals to the CPM in the monthly compliance report following completion of any inspection.

MECH-1 The project owner shall submit, for CBO design review and approval, the proposed final design, specifications and calculations for each plant major piping and plumbing system listed in the CBO-approved master drawing and master specifications list. Physical layout drawings and drawings not related to code compliance and life safety need not be submitted. The submittal shall also include the applicable QA/QC procedures. Upon completion of construction of any such major piping or plumbing system, the project owner shall request the CBO's inspection approval of that construction.

The responsible mechanical engineer shall stamp and sign all plans, drawings, and calculations for the major piping and plumbing systems, subject to CBO design review and approval, and submit a signed statement to the CBO when the proposed piping and plumbing systems have been designed, fabricated, and installed in accordance with all of the applicable laws, ordinances, regulations and industry standards, which may include, but are not limited to:

- American National Standards Institute (ANSI) B31.1 (Power Piping Code);
- ANSI B31.2 (Fuel Gas Piping Code);
- ANSI B31.3 (Chemical Plant and Petroleum Refinery Piping Code);
- ANSI B31.8 (Gas Transmission and Distribution Piping Code);
- Title 24, California Code of Regulations, Part 5 (California Plumbing Code);
- Title 24, California Code of Regulations, Part 6 (California Energy Code, for building energy conservation systems and temperature control and ventilation systems);
- Title 24, California Code of Regulations, Part 2 (California Building Code); and
- Kern County codes.

The CBO may deputize inspectors to carry out the functions of the code enforcement agency.

<u>Verification:</u> At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of any increment of major piping or plumbing construction listed in the CBO-approved master drawing and master specifications list, the project owner shall submit to the CBO for design review and approval the final plans, specifications, and calculations, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with applicable LORS, and shall send the CPM a copy of the transmittal letter in the next monthly compliance report.

The project owner shall transmit to the CPM, in the monthly compliance report following completion of any inspection, a copy of the transmittal letter conveying the CBO's inspection approvals.

MECH-2 For all pressure vessels installed in the plant, the project owner shall submit to the CBO and California Occupational Safety and Health Administration

(Cal-OSHA), prior to operation, the code certification papers and other documents required by applicable LORS. Upon completion of the installation of any pressure vessel, the project owner shall request the appropriate CBO and/or Cal-OSHA inspection of that installation.

The project owner shall:

1. Ensure that all boilers and fired and unfired pressure vessels are designed, fabricated, and installed in accordance with the appropriate section of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, or other applicable code. Vendor certification, with identification of applicable code, shall be submitted for prefabricated vessels and tanks; and

2. Have the responsible design engineer submit a statement to the CBO that the proposed final design plans, specifications, and calculations conform to all of the requirements set forth in the appropriate ASME Boiler and Pressure Vessel Code or other applicable codes.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of on-site fabrication or installation of any pressure vessel, the project owner shall submit to the CBO for design review and approval, the above listed documents, including a copy of the signed and stamped engineer's certification, with a copy of the transmittal letter to the CPM.

The project owner shall transmit to the CPM, in the monthly compliance report following completion of any inspection, a copy of the transmittal letter conveying the CBO's and/or Cal-OSHA inspection approvals.

MECH-3 The project owner shall submit to the CBO for design review and approval the design plans, specifications, calculations, and quality control procedures for any heating, ventilating, air conditioning (HVAC) or refrigeration system. Packaged HVAC systems, where used, shall be identified with the appropriate manufacturer's data sheets.

The project owner shall design and install all HVAC and refrigeration systems within buildings and related structures in accordance with the CBC and other applicable codes. Upon completion of any increment of construction, the project owner shall request the CBO's inspection and approval of that construction. The final plans, specifications and calculations shall include approved criteria, assumptions, and methods used to develop the design. In addition, the responsible mechanical engineer shall sign and stamp all plans, drawings and calculations and submit a signed statement to the CBO that the proposed final design plans, specifications and calculations conform with the applicable LORS.

Verification: At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of construction of any HVAC or refrigeration system, the project owner shall submit to the CBO the required HVAC and refrigeration calculations, plans, and specifications, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with the CBC and other applicable codes, with a copy of the transmittal letter to the CPM.

ELEC-1 Prior to the start of any increment of electrical construction for all electrical equipment and systems 480 Volts or higher (see a representative list, below), with the exception of underground duct work and any physical layout drawings and drawings not related to code compliance and life safety, the project owner shall submit, for CBO design review and approval, the proposed final design, specifications, and calculations. Upon approval, the above listed plans, together with design changes and design change notices, shall remain on the site or at another accessible location for the operating life of the project. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. All transmission facilities (lines, switchyards, switching stations, and substations) are handled in conditions of certification in the **Transmission System Engineering** section of this document.

A. Final plant design plans shall include:

1. one-line diagrHECA for the 13.8 kV, 4.16 kV and 480 V systems; and
2. system grounding drawings.

B. Final plant calculations must establish:

1. short-circuit ratings of plant equipment;
2. ampacity of feeder cables;
3. voltage drop in feeder cables;
4. system grounding requirements;
5. coordination study calculations for fuses, circuit breakers and protective relay settings for the 13.8 kV, 4.16 kV and 480 V systems;
6. system grounding requirements; and
7. lighting energy calculations.

C. The following activities shall be reported to the CPM in the monthly compliance report:

1. Receipt or delay of major electrical equipment;
2. Testing or energization of major electrical equipment; and
3. A signed statement by the registered electrical engineer certifying that the proposed final design plans and specifications conform to requirements set forth in the Energy Commission decision.

<u>Verification:</u> At least 30 days (or project owner- and CBO-approved alternative time frame) prior to the start of each increment of electrical construction, the project owner shall submit to the CBO for design review and approval the above listed documents. The project owner shall include in this submittal a copy of the signed and stamped statement from the responsible electrical engineer attesting compliance with the applicable LORS, and shall send the CPM a copy of the transmittal letter in the next monthly compliance report.

REFERENCES

HEI 2009c - Hydrogen Energy International, LLC /J. Briggs (tn 51735). Revised Application for Certification, dated 05/28/09. Submitted to CEC/Docket Unit on 05/28/09.

GEOLOGY AND PALEONTOLOGY, AND MINERAL RESOURCES

Dal Hunter, Ph.D., C.E.G.

SUMMARY OF CONCLUSIONS

The proposed Hydrogen Energy California (HECA) project is located in an active geologic area of the southern Great Valley geomorphic province in western Kern County, California. Because of its geologic setting, the site could be subject to moderate to high levels of earthquake-related ground shaking. Significant thicknesses of expansive clay soils are also present at the surface. The effects of strong ground shaking and expansive soils must be mitigated, to the extent practical, through structural designs required by the California Building Code (CBC 2007) and the project geotechnical report. The CBC (2007) requires that structures be designed to resist seismic stresses from ground acceleration and, to a lesser extent, liquefaction potential. The design-level geotechnical investigation required for the project by the CBC, and proposed Conditions of Certification **GEN-1**, **GEN-5** and **CIVIL-1**, in the **Facility Design** section of this document, present standard engineering design recommendations for mitigation of seismic shaking and adverse site soil conditions.

There are no known viable geologic or mineralogical resources at the site, with the exception of the oil and gas fields of the Naval Petroleum Reserve. Regionally, paleontological resources have been documented within Quaternary alluvium and Tertiary Tulare Formation, similar to deposits that underlie the project site and numerous new fossil localities were discovered during cursory field explorations at the proposed plant site. Potential impacts would be mitigated through worker training and monitoring by qualified paleontologists, as required by Conditions of Certification, **PAL-1** through **PAL-7**.

Based on its independent research and review, California Energy Commission (Energy Commission) staff believes that the potential is low for significant adverse impacts to the project from geologic hazards during its design life and to potential geologic, mineralogic, and paleontologic resources from the construction, operation, and closure of the proposed project. It is staff's opinion that the proposed HECA project could be designed and constructed in accordance with all applicable laws, ordinances, regulations, and standards and in a manner that both protects environmental quality and assures public safety.

INTRODUCTION

In this section, Energy Commission staff discusses the potential impacts of geologic hazards on the proposed HECA project site as well as geologic, mineralogic, and paleontologic resources. Staff's objective is to ensure that there would be no consequential adverse impacts to significant geological and paleontological resources during project construction, operation, and closure and that operation of the plant would not expose occupants to high-probability geologic hazards. A brief geological and paleontological overview is provided. The section concludes with staff's proposed monitoring and mitigation measures for geologic hazards and geologic, mineralogic, and palentologic resources, with the proposed conditions of certification.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Applicable laws, ordinances, regulations, and standards (LORS) are listed in the application for certification (AFC) (HEI 2008c). The following briefly describes the current LORS for both geologic hazards and resources and mineralogic and paleontologic resources.

Geology, Paleontology and Mineralogy Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	The proposed project is not located on federal land. There are no federal LORS for geologic hazards and resources for this site.
State	
California Building Code (CBC), 2007	The CBC (2007) includes a series of standards that are used in project investigation, design, and construction (including grading and erosion control).
Alquist-Priolo Earthquake Fault Zoning Act, Public Resources Code (PRC), section 2621–2630	Mitigates against surface fault rupture of known active faults beneath occupied structures. Requires disclosure to potential buyers of existing real estate and a 50-foot setback for new occupied buildings. No portions of the site and proposed ancillary facilities are located within designated Alquist-Priolo Earthquake Fault Zones (EFZ).
The Seismic Hazards Mapping Act, PRC Section 2690–2699	Areas are identified that are subject to the effects of strong ground shaking, such as liquefaction, landslides, tsunamis, and seiches.
PRC, Chapter 1.7, sections 5097.5 and 30244	Regulates removal of paleontological resources from state lands, defines unauthorized removal of fossil resources as a misdemeanor, and requires mitigation of disturbed sites.
Warren-Alquist Act, PRC, sections 25527 and 25550.5(i)	The Warren-Alquist Act requires the Energy Commission to “give the greatest consideration to the need for protecting areas of critical environmental concern, including, but not limited to, unique and irreplaceable scientific, scenic, and educational wildlife habitats; unique historical, archaeological, and cultural sites…” With respect to paleontologic resources, the Energy Commission relies on guidelines from the Society for Vertebrate Paleontology.
Local	
Kern County General Plan	Minimizes the risk of injuries and loss of life due to earthquakes, geologic hazards, and other natural disasters. Protects paleontological resources on county lands.
Applicable Standard (General)	

Applicable Law	Description
Society for Vertebrate Paleontology (SVP), 1995	The “Measures for Assessment and Mitigation of Adverse Impacts to Non-Renewable Paleontological Resources: Standard Procedures” is a set of procedures and standards for assessing and mitigating impacts to vertebrate paleontological resources. The measures were adopted in October 1995 by the SVP, a national organization of professional scientists.

SETTING

The HECA project would be constructed on 473 acres of privately owned land located approximately 10 miles west of Bakersfield and 2.5 miles northwest of the unincorporated community of Tupman in west-central Kern County, California. The proposed project site is currently used for irrigated agricultural production.

The HECA would be a base load power generating facility capable of producing approximately 250 megawatts (MW) of electricity from an integrated gasification and combined-cycle hydrogen-fired combustion turbine generator and steam turbine generator system. The facility could also provide a gross output of 390 MW from a combined cycle plant fed by the Gasification Block. Ancillary facilities would include an 8-mile natural gas pipeline, an 8-mile above-ground electrical transmission connection to the existing PG&E electrical grid west of the site, a 15-mile brackish water process supply pipeline, a 7-mile-long potable water supply pipeline, and a 4-mile-long carbon dioxide disposal pipeline. Other onsite improvements would include a process water treatment plant, a petroleum coke (petcoke)/coal gasification facility, control and administrative buildings, a zero liquid discharge system for treatment of process water, and various smaller outbuildings and facilities. Carbon dioxide produced by petcoke and/or coal gasification would be compressed and pumped to the nearby Elk Hills petroleum production field for enhancing oil recovery and for sequestration by reservoir storage (HEI 2008c).

REGIONAL SETTING

The proposed HECA site is located in the southern San Joaquin Valley, which is part of the Great Valley geomorphic province of California (Norris and Webb 1990). The Great Valley is approximately 400 miles long and 60 miles wide, bounded on the north by low-lying hills; on the northeast by the volcanic plateau of the Cascade Range; on the west by the Coast Ranges; on the east by the Sierra Nevada; and on the south by the Coast Ranges and the Tehachapi Mountains. The northern one-third of the Great valley is known as the Sacramento Valley, whereas the southern two-thirds is known as the San Joaquin Valley. The boundary between the two sub-basins is located at the confluence of the Sacramento and San Joaquin Rivers in the delta area near Suisun Bay and the city of Stockton (USGS 1986). The Great Valley is characterized by dissected uplands, and relatively undeformed low alluvial plains and fans, river flood plains and channels, and lake bottoms. In the late Cenozoic era much of the San Joaquin Valley was occupied by shallow brackish and freshwater lakes. Much of the valley fill alluvium is underlain by marine and non-marine sedimentary rocks and crystalline basement which have undergone anticlinal and synclinal folding and faulting related to regional tectonism. Major oil fields, pooled in antiformal structures associated with this regional tectonic activity, have been developed in the southern portion of the San Joaquin Valley.

PROJECT SITE DESCRIPTION

The proposed HECA site would consist of land that has been extensively disturbed by agricultural activities for at least the past 50 years. Elevations on the property range from roughly 282 to 291 feet above mean sea level (msl). Located at approximately 35.33 degrees north latitude by 119.39 degrees west longitude, the majority of the proposed project site is in Section 10, Township 34 South, Range 24 East of the Mount Diablo Baseline and Meridian in western Kern County, near the city of Bakersfield. The 473-acre site is approximately 2.25 miles west and one mile south of the intersection of Interstate 5 and Bellevue Road.

The proposed project site lies on the northeastern flank of the Elk Hills anticline, a structural fold which is part of a series of fold and thrust complexes that mark the southern boundary of the Great Valley geomorphic province. Surface soils are composed of Quaternary (Holocene) age alluvial gravel and sand deposits of the Kern River Valley (Dibblee 2005a; URS 2009a). Alluvium, shed from the Elk Hills southwest of the HECA project site, is likely interbedded with fluvial sands and gravels associated with the Kern River and its tributaries. The alluvial fan deposits are underlain by Pliocene to Pleistocene age non-marine clastic sediments of the Tulare Formation, which extend to depths in excess of 1,000 feet below the surface (Page 1983; Dibblee 2005a). In the Elk Hills where the Tulare Formation is exposed, both upper and lower members are present. The entire HECA site and a majority of the project linears lie in areas mapped as Quaternary alluvial fan deposits. Only the southern portions of the carbon dioxide pipelines extend into areas of the northern Elk Hills mapped as Tulare Formation. Both upper and lower members are crossed, as well as a one-meter thick marker bed known as the Lower limestone, which is a white to light grey, marly carbonate deposited in fresh water (Dibblee 2005a).

The proposed HECA plant site and project linears are not crossed by any known active faults and do not lie within a designated Alquist-Priolo Earthquake Fault Zone (CGS 2002a). A number of major, active faults lie within 70 miles of the site. These faults are discussed in detail under the **Geological Hazards** section later in this section of staff's assessment.

The preliminary geotechnical report for the proposed site (HEI 2008a) indicates that 1.5 to 6 feet of uncontrolled silty sand fill was encountered in borings in the northwest, northeast, and southeast corners of the property. Undisturbed native surface soils are composed of fined grained sandy lean and fat clays and sandy silts that extend to depths of 8 to 19 feet. The clay soils contain medium to high plasticity fines with moderate expansion indices. The fine grained sediments were not identified as Quaternary alluvium or Tulare Formation in the project geotechnical report, but the materials were probably deposited in distal alluvial fan, lacustrine, and/or fluvial environments that are consistent with either unit. Dibblee (2005a) indicates that Quaternary alluvium is Holocene in age, but depth to underlying Pleistocene sediments is undetermined. Silty sand and poorly graded sand designated as Tulare Formation underlies fine-grained soils, and extends to the maximum depth of drilling at 101.5 feet (URS 2009a). The upper portions are medium dense, and become dense to very dense with depth.

The depth to ground water measured in well No. 30S24E11E061M at the eastern edge of the proposed project site was 19.3 feet below ground surface on August 1, 2004 (CDWR 2004). Another well (No. 030S24E14H001M) recorded a historic high ground water level of 247 feet above msl, which is roughly 35 feet below existing ground surface at the site (URS 2009a). However, ground water was not encountered to the maximum depth of drilling at 101.5 feet (URS 2009a). Water levels beneath the site likely vary seasonally and with pumping frequency of nearby irrigation wells.

Existing grade at the proposed power plant site slopes approximately 1% to the northeast (USGS 1954). Site drainage is probably by a combination of infiltration and overland sheet flow. A more complete discussion of on-site drainage is included in the **Water Resources** section of this staff assessment

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section considers two types of impacts. The first is geologic hazards, which could impact the proper functioning of the proposed facility and create life/safety concerns. The second is the potential impacts the proposed facility could have on existing geologic, mineralogic, and paleontologic resources in the area.

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

No federal LORS concerning geologic hazards and geologic and mineralogic resources apply to this project. The California Building Standards Code (CBSC) and CBC (2007) provide geotechnical and geological investigation and design guidelines, which engineers must follow when designing a facility. As a result, the criteria used to assess the significance of a geologic hazard include evaluating each hazard’s potential impact on the design and construction of the proposed facility. Geologic hazards include faulting and seismicity, liquefaction, dynamic compaction, volcanic eruptions, hydrocompaction, subsidence, expansive soils, landslides, tsunamis, and seiches. Other site-specific geologic hazards, such as abandoned mine shafts, are evaluated as appropriate. Of the potential geologic hazards, dynamic compaction, hydrocompaction, subsidence, and expansive soils are geotechnical engineering issues but are not normally associated with concerns for public safety.

The California Environmental Quality Act (CEQA) guidelines, Appendix G, provide a checklist of questions that lead agencies typically address.

- Section (V) (c) includes guidelines that determine if a project will either directly or indirectly destroy a unique paleontological resource or site or a unique geological feature.
- Sections (VI) (a), (b), (c), (d), and (e) focus on whether or not the project would expose persons or structures to geologic hazards.
- Sections (X) (a) and (b) concern the project’s effects on mineral resources.

Staff has reviewed geologic and mineral resource maps for the surrounding area, as well as site-specific information provided by the applicant, to determine if geologic and mineralogic resources exist in the area and to determine if operations could adversely affect geologic and mineralogic resources.

Staff reviewed existing paleontologic information and requested records searches from the Natural History Museum of Los Angeles County (LACM) for the site area. Site-specific information generated by the applicant for the proposed site and ancillary facilities was also reviewed (HEI 2008c, Appendix Q). All research was conducted in accordance with accepted assessment protocol (SVP 1995) to determine whether any known paleontologic resources exist in the general area. If present or likely to be present, conditions of certification which outline required procedures to mitigate impacts to potential resources, are proposed as part of the requirements for project approval.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Ground shaking represents the main geologic hazard at the proposed site. This potential hazard can be effectively mitigated through facility design and recommendations presented in a project site specific geotechnical report. Proposed Conditions of Certification **GEN-1, GEN-5,** and **CIVIL-1** in the **Facility Design** section should also mitigate these impacts to a less than significant level.

The proposed HECA site is not located within an established Mineral Resource Zone (MRZ) and no economically viable mineral deposits are known to be present (CDMG 1990; CDMG 1998; CDMG 1999). The site would be in close proximity to several producing oil and gas fields of the regional Naval Petroleum Reserve, including the Elk Hills, North Coles Levee and South Coles Levee oil fields (Dibblee 2005a). The California Division of Oil, Gas, and Geothermal Resources (DOGGR) identifies a single well within the proposed project area that reportedly did not encounter significant oil or gas deposits. Although discovery of a petroleum resource beneath the HECA plant site is unlikely, directional drilling techniques could allow for exploitation of a resource from outside of the project boundaries. Therefore, the potential for impacting future petroleum production from beneath the site is considered to be low. Petroleum and gas fields underlie portions of the proposed project linears, but their presence is not likely to affect current or future recovery of petroleum reserves.

Staff reviewed correspondence from the LACM (McLeod 2009), and the confidential Paleontological Resources Technical Report (HEI 2008c) for information regarding known fossil localities and stratigraphic unit sensitivity within the proposed project area. The proposed HECA plant site is underlain to depths of 8 to 19 feet by fine-grained sediments that belong to Quaternary alluvial, fluvial and/or lacustrine deposits. Quaternary alluvium is known regionally to contain significant fossil resources, primarily terrestrial vertebrates, and is considered to be highly sensitive (HEI 2008c). Sensitivity increases with depth, according to McLeod (2009), although a depth at which higher sensitivity older allumium would be encountered was not specified. Remains of an extinct species of horse have been recovered along the Bakersfield Canal, and fossil wood is common. Freshwater invertebrate shells and ichnofossils (trace fossils) were identified in Quaternary alluvium at several localities within one mile of the proposed site and project linears during the field survey conducted for the Paleontological Resources

Technical Report attached to the AFC (HEI 2008c, Appendix Q). The low energy environment of deposition for the fine-grained soils underlying the proposed site increases the potential for preservation of significant fossil remains.

Pliocene to Pleistocene age Tulare Formation which underlies the fine-grained sediments has a high sensitivity rating and high potential to contain significant fossil resources. Previously recorded localities from the unit include remains of a wide variety of vertebrate species, as well as freshwater invertebrates and fossil wood. A locality south of one of the carbon dioxide pipeline alternatives yielded fossil remains of rabbit and camel (McLeod 2009). Examination of exposures of the Tulare Formation during the field survey for the Paleontological Resources Technical Report revealed previously unknown occurrences of vertebrate bones, invertebrate shells and fossilized wood within one mile of the site (HEI 2008c, Appendix Q).

Recent, uncontrolled fill is present locally on the proposed site to depths of 1.5 to 6 feet. The material, where encountered, is considered to have no potential for producing meaningful fossils because any fossil remains discovered will be out of their natural geologic context. Similarly, a large portion of the proposed site has been disturbed during agricultural operations, so the upper 1 to 2 feet of the surface is also unlikely to contain significant paleontological resources.

Overall, staff considers the probability that paleontological resources would be encountered during site construction activities to be high. The potential for exposure of paleontological resources would increase with depth and volume of proposed construction excavations. This assessment is based on SVP criteria and the confidential paleontological report appended to the AFC (HEI 2008c). Proposed Conditions of Certification **PAL-1** to **PAL-7** are designed to mitigate paleontological resource impacts, as discussed above, to less than significant levels. These conditions essentially require a worker education program in conjunction with the monitoring of earthwork activities by a qualified professional paleontologist (a paleontologic resource specialist [PRS]).

The proposed conditions of certification allow the Energy Commission’s compliance project manager (CPM) and the applicant to adopt a compliance monitoring scheme ensuring compliance with LORS applicable to geologic hazards and the protection of geologic, mineralogic, and paleontologic resources.

Based on the information below, it is staff’s opinion that the potential for significant adverse, direct or indirect impacts to the proposed project, from geologic hazards, and to potential geologic, mineralogic, and paleontologic resources, from the proposed project, could be mitigated to reduce impacts to a less than significant level.

GEOLOGICAL HAZARDS

The AFC (HEI 2008c) provides documentation of potential geologic hazards at the proposed site, including site-specific subsurface information generated by a preliminary geotechnical investigation (HEI 2008c, Appendix P). Review of the AFC, coupled with staff’s independent research, indicates that the potential for geologic hazards to impact the proposed plant site during its practical design life would be low if recommendations for mitigation of seismic shaking and expansive soils are adopted and followed.

Geologic hazards related to seismic shaking and adverse soil conditions are addressed in a project geotechnical report per CBC (2007) requirements (HEI 2008c, Appendix P).

Staff's independent research included the review of available geologic maps, reports, and related data of the proposed HECA site. Geological information was available from the California Geological Survey (CGS), California Division of Mines and Geology (CDMG, now know as CGS), the U.S. Geological Survey (USGS), the American Geophysical Union, the Geological Society of America, and other organizations.

Faulting and Seismicity

Energy Commission staff reviewed numerous CGS, USGS, and other publications, (CGS 2002a and b; CGS 2007; CDMG 1994; CDMG 2003; Fiore et al. 2007; Nicholson 1990; SCEDC 2008; Smith 1992; USGS 2006; USGS 2008), informational websites, and analytical and database software (Blake 2000a and b) in order to gather data on the location, recency, and type of faulting in the project area. Type A and B faults within 70 miles (112 kilometers) of the site under consideration are listed in **Geology, Paleontology and Mineralogy Table 2**. Type A faults have slip-rates of $\geq$5 mm per year and are capable of producing an earthquake of magnitude 7.0 or greater. Type B faults have slip-rates of 2 to 5 mm per year and are capable of producing an earthquake of magnitude 6.5 to 7.0. The fault type, potential magnitude, and distance from the proposed site are summarized in **Geology, Paleontology and Mineralogy Table 2**.

Type C and otherwise undifferentiated faults which are more than 20 miles from the proposed site are not discussed here because they are not likely to produce an earthquake of sufficient magnitude that could affect the project.

Twenty Type A and B faults and fault segments were identified within 62 miles (100 kilometers) of the proposed site. All three of the Type A faults are segments of the San Andreas Fault System. The closest of these is the Carrizo segment located 21 miles to the west and southwest. The San Andreas Fault is the dominant active tectonic feature of the Coast Ranges and represents the boundary of the North American and Pacific plates. Right-lateral strike-slip motion occurs along the structural zone at an average rate of 2.5 centimeters per year. The Carrizo segment is capable of producing a moment magnitude earthquake of 7.8 (7.8M). Surface rupture occurred along a 225 mile stretch of the San Andreas fault, which included the Carrizo segment, Cholame segment to the northwest, and Mojave segment to the southeast, during the Magnitude 7.9 Fort Tejon Earthquake in 1857 (SCEDC 2008). The southern end of the Cholame segment is located approximately 27 miles northwest of the proposed site, and has been assigned a maximum moment magnitude of 7.3.

Faulting and uplift that resulted in the formation of the Elk Hills anticline began in the Miocene and continued through present time (Fiore et al. 2007; Nicholson 1990). Although historic surface rupture has not been observed along faults in the Elk Hills, Quaternary age movement is well documented. Two major groups of Quaternary faults are mapped in the Elk Hills area (CDMG 1994; Dibblee 2005a; Fiore et al. 2007; Nicholson 1990). At least four northeast-striking faults are present in the eastern Elk Hills, the nearest of which is located approximately 500 feet southeast of the south end of one of the proposed carbon dioxide pipeline options. Eleven faults in the western Elk

Hills are oriented east to northeast and northwest, and are located at least 6 miles west of the proposed HECA plant site (CDMG 1994; Dibblee 2005b).

The estimated bedrock peak horizontal ground acceleration (Site Class B) for the power plant is 0.46 times the acceleration of gravity (0.46g) (USGS 2008). Based on drilling data, including standard penetration resistance blowcounts and shear-wave velocities, and on the soil profile generated for the site by the preliminary geotechnical investigation, the soils at the proposed HECA project site were determined to be Site Class D (CBC 2007; HEI 2008c). Buildings and structures are required to be designed with adequate strength to resist the effects of Design Earthquake Ground Motion, as defined by the CBC (2007). This motion is calculated using the site classification, occupancy categories and site coefficients, which in turn are used to determine the design spectral response acceleration parameters at short and 1-second periods. These parameters are generally provided in the design-level geotechnical report for the specific project site.

Carbon dioxide produced during operation of the proposed HECA plant would be captured, piped southward to the actively producing Elk Hills oil and gas fields, and injected into porous rocks several thousand feet underground. These proposed operations would sequester the carbon dioxide underground, preventing its release into the atmosphere, and enhance oil recovery (Terralog 2008). The proposed volume of carbon dioxide injection would be less than the quantities of water, steam and gas currently injected to increase oil production in the Elk Hills. Fluid injection is known to have increased levels of small-scale seismicity at other locations in the United States, although none has been documented as a result of water, steam and gas injection in the Elk Hills oil and gas fields. Any additional seismic event resulting from proposed carbon dioxide injection is not expected to exceed a magnitude 4 earthquake (Terralog 2008). The maximum anticipated peak acceleration the proposed HECA site would experience is on the order of 0.01 g, which is more than an order of magnitude less intense than site accelerations associated with maximum credible earthquakes on faults listed in **Geology, Paleontology and Mineralogy Table 2**. Since the proposed HECA plant would be designed to withstand much higher levels of ground shaking associated with earthquakes on active faults within 30 miles of the site, the potential for minor levels of increased seismicity associated with carbon dioxide injection poses no additional geologic hazard.

The potential for strong ground shaking will be addressed in proposed Facility Design Condition of Certification **GEN-1**. Proper design in accordance with this condition, as well as with requirements presented in a site-specific, design-level geotechnical report, should adequately mitigate seismic hazards to the current standards of practice.

Geology, Paleontology and Mineralogy Table 2
Active Faults in the Proposed Project Area

Fault Name	Distance From Site (miles)	Maximum Earthquake Magnitude (Mw)	Estimated Peak Site Acceleration (g)	Movement and Strike	Slip Rate mm/yr	Fault Type
San Juan	34.9	7.1	0.107	Right-Lateral Strike Slip (Northwest)	1.0	B
Big Pine	41.3	6.9	0.085	Left-Lateral Strike Slip (North)	0.8	B
Garlock (West)	43.9	7.3	0.100	Left-Lateral Strike Slip (North)	6.0	B
San Gabriel	51.5	7.2	0.084	Right-Lateral Strike Slip (Northwest)	1.0	B
San Luis Range (South Margin)	53.0	7.2	0.100	Reverse (North)	0.2	B
North Channel Slope	53.7	7.4	0.110	Reverse (West)	2.0	B
Great Valley 14	54.7	6.4	0.064	Reverse (North) Blind Thrust	1.5	B
Santa Ynez (East)	56.0	7.1	0.074	Left-Lateral Strike Slip (North)	2.0	B
M.Ridge – Arroyo Parida - Santa Ana	56.5	7.2	0.095	Reverse (West)	0.4	B
Santa Ynez (West)	57.40	7.1	0.073	Left-Lateral Strike Slip (North)	2.0	B
San Cayetano	58.4	7.0	0.083	Reverse (West)	6.0	B
San Andreas - Parkfield	59.2	6.5	0.052	Right-Lateral Strike Slip (Northwest)	34.0	A
Red Mountain	61.6	7.0	0.080	Reverse (West)	2.0	B
Los Alamos – West Baseline	61.8	6.9	0.075	Reverse (West)	0.7	B
Los Osos	62.1	7.0	0.079	Reverse (Southwest)	0.5	B
San Andreas – Whole	21.1	8.0	0.253	Right-Lateral Strike Slip (Northwest)	34.0	A
San Andreas – Carrizo, Ft. Tejon Rupture	21.1	7.8	0.228	Right-Lateral Strike Slip (Northwest)	34.0	A
White Wolf	23.5	7.3	0.196	Reverse, Left-Lateral, Oblique (West)	2.0	B
San Andreas – Cholame	27.2	7.3	0.144	Right-Lateral Strike Slip (Northwest)	34.0	A
Pleito Thrust	27.3	7.0	0.150	Reverse (West)	2.0	B

Liquefaction

Liquefaction is a condition in which a cohesionless or even slightly plastic soil may lose shear strength due to a sudden increase in pore water pressure caused by ground shaking during an earthquake. Four of the parameters used to assess the potential for liquefaction are soil density, soil texture, depth to ground water, and the peak horizontal ground acceleration estimated for the site. Historic depths to ground water at the proposed project site range from approximately 19 feet (CDWR 2004) to 35 feet below the existing ground surface, although ground water was not encountered in hollow-stem auger borings advanced to a maximum depth of 101.5 feet. SPT testing conducted during the site geotechnical investigation indicates that soils below approximately 15 feet are generally too dense to be subject to liquefaction (HEI 2008c). Therefore the potential for liquefaction due to seismic shaking is negligible.

Lateral Spreading

Lateral spreading of the ground surface can occur within liquefiable beds during seismic events. Lateral spreading generally requires an abrupt change in slope—that is, a nearby steep hillside or deeply eroded stream bank, etc.—but can also occur on gentle slopes such as are present at the project site. Other factors such as distance from the epicenter, magnitude of the seismic event, and thickness and depth of liquefiable layers also affect the amount of lateral spreading. Because the proposed site is not subject to liquefaction, the potential for lateral spreading on the surface during seismic events would be negligible.

Dynamic Compaction

Dynamic compaction of soils results when relatively unconsolidated granular materials experience vibration associated with seismic events. The vibration causes a decrease in soil volume, as the soil grains tend to rearrange into a more dense state (an increase is soil density). The decrease in volume can result in settlement of overlying structural improvements. The site specific geotechnical investigation indicates the alluvial deposits in the proposed site subsurface are generally too dense to allow significant dynamic compaction (URS 2009a).

Hydrocompaction

Hydrocompaction (also known as hydro-collapse) is generally limited to young soils that were deposited rapidly in a saturated state, most commonly by a flashflood. The soils dry quickly, leaving an unconsolidated, low density deposit with a high percentage of voids. Foundations built on these types of compressible materials can settle excessively, particularly when landscaping irrigation dissolves the weak cementation that is preventing the immediate collapse of the soil structure. Hydrocompaction is the process of the loss of soil volume upon the application of water.

Hydrocompaction has been documented in several areas in the southern San Joaquin Valley southwest and west of Bakersfield; however, the proposed HECA project site would not be located within any of these designated areas (Kern County 2000; USGS 1984). The potential for significant consolidation due to hydrocompaction is considered remote. The proposed site area has been irrigated and cultivated extensively, which would likely have induced settlement in soils that had a potential for hydrocompaction. The proposed site specific geotechnical investigation also indicates the subsurface alluvial deposits which underlie the site would generally be too dense to experience significant hydrocompaction (URS 2009a).

Subsidence

Subsidence of surficial and near surface soil units can result from loading of loose or soft soils by foundations, or by the extraction of fluids from the subsurface. Load-induced consolidation has been addressed by the project geotechnical investigation (HEI 2008c, Appendix P), as required by Facility Design Conditions of Certification **GEN-5** and **CIVIL-1.**

Regional ground subsidence is typically caused by petroleum or ground water withdrawal that increases the effective unit weight of the soil profile, which in turn increases the effective stress on the deeper soils. This results in consolidation or settlement of the underlying soils. Subsidence due to ground water withdrawal has occurred throughout much of the San Joaquin Valley in the decades prior to the 1970's (USGS 1984; USGS 2000). Ireland and others show the site as lying outside areas with documented subsidence, in excess of one foot, due to ground water withdrawal (USGS 1984). Petroleum and gas fields are also located in the Elk Hills adjacent to the proposed project site area and throughout the southern portion of the Great Valley Geomorphic Province (CDC, 1998). Despite the proximity of oil fields relative to the proposed site, subsidence in the area was not indicated in the Geologic Hazards and Resources section of the AFC, or in the supporting preliminary geotechnical report (HEI 2008c, Appendix P) The project would not increase ground water withdrawal and, consequently, would not cause subsidence due to ground water pumping.

Expansive Soils

Soils that contain a high percentage of expansive clay minerals are prone to expansion, if subjected to an increase in water content. Expansion potential of soils is usually measured by plasticity index and expansive index tests. The most hazardous soils have high clay contents, and the clays have a high shrink-swell potential and a high plasticity index**.** Near surface soils in the proposed project vicinity consist generally of sandy lean and fat clays, with measured plasticity indices of 29 and 41, and expansion indices of 73 and 83 (HEI 2008c, Appendix P). The soils classify as moderately expansive, which could pose a hazard to facility foundations if mitigation measures are not implemented (URS 2009a). Further investigation should be conducted to delineate the precise location of expansive surface soils relative to proposed HECA plant facilities. Recommendations to mitigate their effects should then be provided in a site-specific, design-level geotechnical report, per **GEN-1**, **GEN-5**, and **CIVIL-1**.

Facility Design Conditions of Certification **GEN-1, GEN-5** and **CIVIL-1**, as well as recommendations in a design-level geotechnical report, should mitigate the hazards due to expansive soils to a less than significant level.

Landslides

The proposed site is essentially flat and would not be susceptible to landslides or other forms of slope instability.

Flooding

The proposed site and linear facilities would be located in a shaded Zone X defined as "Areas of 0.2% annual chance flood, areas of 1% annual chance flood with average depth of less than one foot, or with drainage area of less than one (1) square mile; areas protected by levee from 1% annual chance flood" (FEMA 2008).

Tsunamis and Seiches

The proposed project and associated linear facilities would not be located near any significant surface water bodies and therefore there is no potential for impacts due to tsunamis and seiches.

GEOLOGIC, MINERALOGIC, AND PALEONTOLOGIC RESOURCES

Energy Commission staff has reviewed applicable geologic maps, reports, and on-line resources for this area (CDMG 1962; CDMG 1965; CDMG 1990; CDMB 1994; CDMG 1998; CDMG 1999; CDMG 2003; Dibblee 2005a and b). Staff did not identify any geological or mineralogical resources at the proposed energy facility location. The proposed site would be in proximity to producing oil and gas fields; however, these fields are located beneath the structural anticlines of the Elk Hills south and west of the site and the potential for production from beneath the HECA site is considered to be low (CDC 2008).

Energy Commission staff reviewed the Paleontological Resources Technical Report attached as Appendix Q of the AFC (HEI 2008c) and the archival literature and records search conducted by the LACM (McLeod 2009). Paleontological resources were documented on the proposed plant site during the project paleontological field survey and significant vertebrate fossils are found regionally in Quaternary alluvium and Pliocene to Pleistocene Tulare Formation. Both units, which are present at the surface or at shallow depths beneath the proposed project site and linears, are considered to be highly sensitive and have a high potential for containing significant paleontological resources. Sensitivity in Quaternary alluvium, however, is relatively low near the surface and increases with depth, although the depth is unspecified and undetermined (McLeod, 2009). Therefore, all undisturbed Quaternary alluvium should be treated as highly sensitive, until determined otherwise by a qualified professional paleontologist. Localized uncontrolled fill materials have no potential for containing significant paleontological resources. The surface of much of the proposed site has been disturbed as a result of agricultural development for crop production, so the upper 1 to 2 feet would be unlikely to contain fossil remains in their natural context.

This assessment is based on SVP criteria (SVP 1995), the Paleontological Resources Technical Report appended to the AFC (HEI 2008c), and the independent paleontological assessment provided by the LACM (McLeod 2009). Proposed Conditions of Certification **PAL-1** to **PAL-7** are designed to mitigate paleontological resource impacts, as discussed above, to less than significant levels. These conditions essentially would require a worker education program in conjunction with the monitoring of earthwork activities by a qualified professional paleontologist (PRS).

All proposed Conditions of Certification (**GEN-1**, **GEN-5**, **CIVIL-1**, and **PAL-1** to **PAL-7**) allow the Energy Commission's CPM and the applicant to adopt monitoring schemes to ensure compliance with all LORS applicable to geologic hazards and the protection of geologic, mineralogic, and paleontologic resources.

Construction Impacts and Mitigation

The design-level geotechnical investigation, required for the proposed project by the CBC (2007) and proposed Conditions of Certification **GEN-1**, **GEN-5** and **CIVIL-1** of the **Facility Design** section of this document provide standard engineering design recommendations for mitigation of earthquake ground shaking, excessive settlement and expansive soils.

As noted above, no viable geologic or mineralogic resources are known to exist in the vicinity of the proposed construction site or project linears, with the exception of the Elk Hills and associated oil and gas fields. Current and future oil and gas production from these deposits would not be expected to be adversely impacted by proposed construction of the HECA plant site and project linears.

Quaternary alluvium and Pliocene to Pleistocene Tulare Formation deposits beneath the proposed site have a high sensitivity rating for paleontologic impacts. Based on the soils profile, SVP assessment criteria, and the shallow depth of potentially fossiliferous geologic units, staff considers the probability of encountering paleontological resources during construction of the proposed HECA project to be high. Quaternary alluvium near the surface is less sensitive relative to deeper and older alluvium (McLeod 2009), however, all Quaternary sediments at the project site should be considered to have a high sensitivity rating until determined otherwise by a qualified professional paleontologist. Since the upper portion of the surface has been disturbed during agricultural operations, the upper 1 to 2 feet of ground would not be likely to yield fossil remains in their natural context. Any excavation into undisturbed native ground at the surface or below disturbed material at the proposed plant site and along project linears, would be considered to have a high potential to encounter significant paleontological resources.

Mass grading operations within proposed structure footprints, that could be required for removal of expansive clays, would have the potential to disturb paleontological resources. Fossil remains could also be encountered in deep trenches excavated for utilities, and for construction of drilled shaft foundations that may be used to support heavily loaded structures. Any fossil brought to the surface by drilling operations would be badly disturbed and out of context.

Proposed Conditions of Certification **PAL-1 to PAL-7** are designed to mitigate any paleontological resource impacts, as discussed above, to a less than significant level. Essentially, these conditions would require a worker education program in conjunction with monitoring of earthwork activities by qualified professional paleontologists (PRS). Earthwork is halted any time potential fossils are recognized by either the paleontologist or the worker. The science of paleontology is advanced by the discovery, study and curation of new fossils. These fossils can be significant if they represent a new species, verify a known species in a new location, provide museum quality specimens, and/or if they include structures of similar specimens that had not previously been found preserved, among other criteria. Most fossil discoveries are the result of excavations, either purposeful in known or suspected fossil localities or as the result of excavations made during earthwork for civil improvements or mineral extraction. Proper monitoring of excavations at the proposed HECA facility, in accordance with an approved Paleontological Monitoring and Mitigation Plan (proposed **PAL-3**), could result in fossil discoveries which would enhance our understanding of the prehistoric climate, geology, and geographic setting of the region for the benefit of current and future generations. When properly implemented, the conditions of certification yield a net gain to the science of paleontology since fossils that would not otherwise have been discovered can be collected, identified, studied, and properly curated.

A PRS is retained, for the project by the applicant, to produce a monitoring and mitigation plan, conduct the worker training, and provide the monitoring, per **PAL-3** through **PAL-6**. This plan is based on anticipated conditions, typically deduced from the available regional-level geologic mapping, museum records, and a brief site reconnaissance. Geologic conditions on the scale of a single project site can differ greatly from what was anticipated. During the monitoring, the PRS may petition the Energy Commission for a change in the monitoring protocol. Most commonly, this is a request for lesser monitoring after sufficient monitoring has been performed to ascertain that there is little chance of finding significant fossils (**PAL-5**). In other cases, the PRS may propose increased monitoring due to unexpected fossil discoveries or in response to repeated out-of-compliance incidents by the earthwork contractor. At the proposed HECA site, a PRS may evaluate Quaternary alluvium exposed in new excavations, and determine a minimum depth above which the potential for encountering paleontological resources is low. The PRS may then recommend decreased monitoring in excavations above this depth.

Based upon the literature and archives search, field surveys, and compliance documentation for the proposed project, the applicant proposes monitoring and mitigation measures for construction of proposed power plant. Energy Commission staff agrees with the applicant that the project can be designed and constructed to minimize the effects of geologic hazards at the site, during project design life, and that impacts to vertebrate, invertebrate and trace fossils encountered during construction can be mitigated to levels of insignificance.

Operation Impacts and Mitigation

The operation of the HECA Project would not present additional risk to geological resources (none identified) or paleontological resources. Once ground disturbing activity is complete plant operation has no real potential to further affect paleontological resources. Therefore, routine plant operation would not increase potential cumulative effects on paleontological resources. The longer the plant operates, however, the more likely it is to be affected by geological hazards, primarily earthquake-related ground shaking. For example, USGS data indicates that there is a 20& probability that a bedrock ground acceleration of 0.206g will be exceeded at the site in any 50-year interval (USGS 2006). This equates to a recurrence interval of about 250 years. The CBC (2009) requires that the structures be designed for a 2,500 recurrence interval event (2% probability in 50 years) which shows a much higher bedrock ground acceleration of 0.46g. The longer the project operates, the higher the probability of both an earthquake and high ground acceleration. This situation is the same for all developments anywhere and not unique to this project at this site. The design requirements of the CBC are intended to protect occupants from building collapse during the design-level earthquake, one with only 2% probability of being exceeded in any 50-year interval. The code does not require that the structures be salvageable after such an event. Construction and operation of the plant does not increase the potential of geological hazards at the site, but the potential for earthquake-generated ground shaking at the site unavoidably increases with every year of operation.

CUMULATIVE IMPACTS AND MITIGATION

The geographic area considered for cumulative impacts on geology and paleontology is the south portion of the San Joaquin Valley, the southern end of the Great Valley geomorphic province in central California (Norris and Webb 1990). The potential cumulative impacts are limited to those involving paleontological resources since no geological or mineralogical resources have been identified within the boundaries of the proposed project. There are no geological hazards with potential cumulative effects, other than regional subsidence from ground water withdrawal. Significant ground water withdrawal is not part of the proposed project. No adverse cumulative impacts would be anticipated with respect to current and future oil and gas recovery from the Naval Petroleum Reserve.

The potential impacts to paleontological resources due to construction activities would be mitigated by proposed Conditions of Certification **PAL-1 to PAL-7**. Construction of the project would require localized excavation and trenching. Because the project area lies predominantly within geological units with high paleontological sensitivity, the required excavation could, potentially, damage paleontological resources. Any damage could be cumulative to damage from other projects within the same geological formations. Implementation and enforcement of a properly designed Paleontological Resource Monitoring and Mitigation Plan (PRMMP; proposed **PAL-3**) at the HECA site should result in a net gain to the science of paleontology by allowing fossils that would not otherwise have been found, to be recovered, identified, studied, and preserved. Cumulative impacts from HECA, in consideration with other nearby similar projects, should therefore be either neutral (no fossils encountered) or positive (fossils encountered, preserved, and identified).

Staff believes that the potential for significant adverse cumulative impacts to the proposed project from geologic hazards, during the project's design life, would be low, and that the potential for isolated and cumulative impacts to geologic, mineralogic, and paleontologic resources would be very low.

The proposed conditions of certification allow the Energy Commission CPM and the applicant to adopt a compliance monitoring scheme ensuring compliance with applicable LORS for geologic hazards and geologic, mineralogic, and paleontologic resources.

FACILITY CLOSURE

Facility closure activities would not be expected to impact geologic, paleontologic, or mineralogic resources since no such resources are known to exist at the project location. In addition, the decommissioning and closure of the project should not negatively affect geologic, mineralogic, or paleontologic resources since the majority of the ground disturbed during plant decommissioning and closure would have been already disturbed, and mitigated as required, during construction and operation of the proposed project.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff has not received any agency or public comments regarding geologic hazards, mineral resources, or paleontology at this time.

CONCLUSIONS

The proposed project would comply with applicable LORS, provided that the proposed conditions of certification are followed. The design and construction of the proposed project would have no adverse, isolated, or cumulative impacts with respect to geologic, mineralogic, and paleontologic resources. Staff proposes to ensure compliance with applicable LORS through the adoption of the proposed conditions of certification listed below.

PROPOSED CONDITIONS OF CERTIFICATION

General conditions of certification with respect to engineering geology are proposed under Conditions of Certification **GEN-1, GEN-5, and CIVIL-1** in the **FACILITY DESIGN** section. Proposed paleontological Conditions of Certification follow. It is staff's opinion that the likelihood of encountering paleontologic resources is high at the plant site and along project linears. Staff will consider reducing monitoring intensity, at the recommendation of the project paleontologic resource specialist, following examination of sufficient, representative deep excavations that produce no significant fossil remains.

PAL-1 The project owner shall provide the CPM with the resume and qualifications of its PRS for review and approval. If the approved PRS is replaced prior to completion of project mitigation and submittal of the Paleontological Resources Report, the project owner shall obtain CPM approval of the replacement PRS. The project owner shall keep resumes on file for qualified paleontological resource monitors (PRMs). If a PRM is replaced, the resume of the replacement PRM shall also be provided to the CPM.

The PRS resume shall include the names and phone numbers of references. The resume shall also demonstrate to the satisfaction of the CPM the appropriate education and experience to accomplish the required paleontological resource tasks.

As determined by the CPM, the PRS shall meet the minimum qualifications for a vertebrate paleontologist as described in the SVP guidelines of 1995. The experience of the PRS shall include the following:

1. Institutional affiliations, appropriate credentials, and college degree;
2. Ability to recognize and collect fossils in the field;
3. Local geological and biostratigraphic expertise;
4. Proficiency in identifying vertebrate and invertebrate fossils; and

5. At least three years of paleontological resource mitigation and field experience in California and at least one year of experience leading paleontological resource mitigation and field activities.

The project owner shall ensure that the PRS obtains qualified paleontological resource monitors to monitor as he or she deems necessary on the project. Paleontologic resource monitors shall have the equivalent of the following qualifications:

- BS or BA degree in geology or paleontology and one year of experience monitoring in California; or
- AS or AA in geology, paleontology, or biology and four years' experience monitoring in California; or
- Enrollment in upper division classes pursuing a degree in the fields of geology or paleontology and two years of monitoring experience in California.

Verification: (1) At least 60 days prior to the start of ground disturbance, the project owner shall submit a resume and statement of availability of its designated PRS for on-site work.

(2) At least 20 days prior to ground disturbance, the PRS or project owner shall provide a letter with resumes naming anticipated monitors for the project, stating that the identified monitors meet the minimum qualifications for paleontological resource monitoring required by the condition. If additional monitors are obtained during the project, the PRS shall provide additional letters and resumes to the CPM. The letter shall be provided to the CPM no later than one week prior to the monitor's beginning on-site duties.

(3) Prior to the termination or release of a PRS, the project owner shall submit the resume of the proposed new PRS to the CPM for review and approval.

PAL-2 The project owner shall provide to the PRS and the CPM, for approval, maps and drawings showing the footprint of the power plant, construction lay-down areas, and all related facilities. Maps shall identify all areas of the project where ground disturbance is anticipated. If the PRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the PRS and CPM. The site grading plan and plan and profile drawings for the utility lines would be acceptable for this purpose. The plan drawings should show the location, depth, and extent of all ground disturbances and be at a scale between 1 inch = 40 feet and 1 inch = 100 feet. If the footprint of the project or its linear facilities changes, the project owner shall provide maps and drawings reflecting those changes to the PRS and CPM.

If construction of the project proceeds in phases, maps and drawings may be submitted prior to the start of each phase. A letter identifying the proposed schedule of each project phase shall be provided to the PRS and CPM. Before work commences on affected phases, the project owner shall notify the PRS and CPM of any construction phase scheduling changes.

At a minimum, the project owner shall ensure that the PRS or PRM consults weekly with the project superintendent or construction field manager to confirm area(s) to be worked the following week and until ground disturbance is completed.

<u>Verification:</u> (1) At least 30 days prior to the start of ground disturbance, the project owner shall provide the maps and drawings to the PRS and CPM.

(2) If there are changes to the footprint of the project, revised maps and drawings shall be provided to the PRS and CPM at least 15 days prior to the start of ground disturbance.

(3) If there are changes to the scheduling of the construction phases, the project owner shall submit a letter to the CPM within 5 days of identifying the changes.

PAL-3 The project owner shall ensure that the PRS prepares, and the project owner submits to the CPM for review and approval, a PRMMP to identify general and specific measures to minimize potential impacts to significant paleontological resources. Approval of the PRMMP by the CPM shall occur prior to any ground disturbance. The PRMMP shall function as the formal guide for monitoring, collecting, and sampling activities and may be modified with CPM approval. This document shall be used as the basis of discussion when on-site decisions or changes are proposed. Copies of the PRMMP shall reside with the PRS, each monitor, the project owner’s on-site manager, and the CPM.

The PRMMP shall be developed in accordance with the guidelines of the SVP (1995) and shall include, but not be limited, to the following:

1. Assurance that the performance and sequence of project-related tasks, such as any literature searches, pre-construction surveys, worker environmental training, fieldwork, flagging or staking, construction monitoring, mapping and data recovery, fossil preparation and collection, identification and inventory, preparation of final reports, and transmittal of materials for curation will be performed according to PRMMP procedures;

2. Identification of the person(s) expected to assist with each of the tasks identified within the PRMMP and the conditions of certification;

3. A thorough discussion of the anticipated geologic units expected to be encountered, the location and depth of the units relative to the project when known, and the known sensitivity of those units based on the occurrence of fossils either in that unit or in correlative units;

4. An explanation of why, how, and how much sampling is expected to take place and in what units. Include descriptions of different sampling procedures that shall be used for fine-grained and coarse-grained units;

5. A discussion of the locations of where the monitoring of project construction activities is deemed necessary, and a proposed plan for monitoring and sampling;

6. A discussion of procedures to be followed in the event of a significant fossil discovery, halting construction, resuming construction, and how notifications will be performed;

7. A discussion of equipment and supplies necessary for collection of fossil materials and any specialized equipment needed to prepare, remove, load, transport, and analyze large-sized fossils or extensive fossil deposits;

8. Procedures for inventory, preparation, and delivery for curation into a retrievable storage collection in a public repository or museum, which meet the Society of Vertebrate Paleontology's standards and requirements for the curation of paleontological resources;

9. Identification of the institution that has agreed to receive data and fossil materials collected, requirements or specifications for materials delivered for curation and how they will be met, and the name and phone number of the contact person at the institution; and

10. A copy of the paleontological Conditions of Certification.

Verification: At least 30 days prior to ground disturbance, the project owner shall provide a copy of the PRMMP to the CPM. The PRMMP shall include an affidavit of authorship by the PRS and acceptance of the PRMMP by the project owner evidenced by a signature.

PAL-4 Prior to ground disturbance and for the duration of construction activities involving ground disturbance, the project owner and the PRS shall prepare and conduct weekly CPM-approved training for the following workers: project managers, construction supervisors, foremen and general workers involved with or who operate ground-disturbing equipment or tools. Workers shall not excavate in sensitive units prior to receiving CPM-approved worker training. Worker training shall consist of an initial in-person PRS training program, or may utilize a CPM-approved video or other presentation format, during the project kick off for those mentioned above. Following initial training, a CPM-approved video or other approved training presentation/materials, or in-person training may be used for new employees. The training program may be combined with other training programs prepared for cultural and biological resources, hazardous materials, or other areas of interest or concern. No ground disturbance shall occur prior to CPM approval of the Worker Environmental Awareness Program (WEAP), unless specifically approved by the CPM.

The WEAP shall address the possibility of encountering paleontological resources in the field, the sensitivity and importance of these resources, and legal obligations to preserve and protect those resources.

The training shall include:

1. A discussion of applicable laws and penalties under the law;
2. Good quality photographs or physical examples of vertebrate fossils for project sites containing units of high paleontologic sensitivity;
3. Information that the PRS or PRM has the authority to halt or redirect construction in the event of a discovery or unanticipated impact to a paleontological resource;
4. Instruction that employees are to halt or redirect work in the vicinity of a find and to contact their supervisor and the PRS or PRM;
5. An informational brochure that identifies reporting procedures in the event of a discovery;
6. A WEAP certification of completion form signed by each worker indicating that he/she has received the training; and
7. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

Verification: (1) At least 30 days prior to ground disturbance, the project owner shall submit the proposed WEAP, including the brochure, with the set of reporting procedures for workers to follow.

(2) At least 30 days prior to ground disturbance, the project owner shall submit the training program presentation/materials to the CPM for approval if the project owner is planning to use a presentation format other than an in-person trainer for training.

(3) If the owner requests an alternate paleontological trainer, the resume and qualifications of the trainer shall be submitted to the CPM for review and approval prior to installation of an alternate trainer. Alternate trainers shall not conduct training prior to CPM authorization.

(4) In the monthly compliance report (MCR), the project owner shall provide copies of the WEAP certification of completion forms with the names of those trained and the trainer or type of training (in-person or other approved presentation format) offered that month. The MCR shall also include a running total of all persons who have completed the training to date.

PAL-5 The project owner shall ensure that the PRS and PRM(s) monitor consistent with the PRMMP all construction-related grading, excavation, trenching, and augering in areas where potential fossil-bearing materials have been identified, both at the site and along any constructed linear facilities associated with the project. In the event that the PRS determines full-time monitoring is not necessary in locations that were identified as potentially fossil bearing in the PRMMP, the project owner shall notify and seek the concurrence of the CPM.

The project owner shall ensure that the PRS and PRM(s) have the authority to halt or redirect construction if paleontological resources are encountered. The project owner shall ensure that there is no interference with monitoring activities unless directed by the PRS. Monitoring activities shall be conducted as follows:

1. Any change of monitoring from the accepted schedule in the PRMMP shall be proposed in a letter or email from the PRS and the project owner to the CPM prior to the change in monitoring and will be included in the monthly compliance report. The letter or email shall include the justification for the change in monitoring and be submitted to the CPM for review and approval.

2. The project owner shall ensure that the PRM(s) keep a daily monitoring log of paleontological resource activities. The PRS may informally discuss paleontological resource monitoring and mitigation activities with the CPM at any time.

3. The project owner shall ensure that the PRS notifies the CPM within 24 hours of the occurrence of any incidents of non-compliance with any paleontological resources conditions of certification. The PRS shall recommend corrective action to resolve the issues or achieve compliance with the conditions of certification.

4. For any significant paleontological resources encountered, either the project owner or the PRS shall notify the CPM within 24 hours, or Monday morning in the case of a weekend event, where construction has been halted because of a paleontological find.

The project owner shall ensure that the PRS prepares a summary of monitoring and other paleontological activities placed in the monthly compliance reports. The summary will include the name(s) of PRS or PRM(s) active during the month; general descriptions of training and monitored construction activities; and general locations of excavations, grading, and other activities. A section of the report shall include the geologic units or subunits encountered, descriptions of samplings within each unit, and a list of identified fossils. A final section of the report will address any issues or concerns about the project relating to paleontologic monitoring, including any incidents of non-compliance or any changes to the monitoring plan that have been approved by the CPM. If no monitoring took place during the month, the report shall include an explanation in the summary as to why monitoring was not conducted.

Verification: The project owner shall ensure that the PRS submits the summary of monitoring and paleontological activities in the MCR. When feasible, the CPM shall be notified 10 days in advance of any proposed changes in monitoring different from the plan identified in the PRMMP. If there is any unforeseen change in monitoring, the notice shall be given as soon as possible prior to implementation of the change.

PAL-6 The project owner, through the designated PRS, shall ensure that all components of the PRMMP are adequately performed including collection of fossil materials, preparation of fossil materials for analysis, analysis of fossils, identification and inventory of fossils, the preparation of fossils for curation, and the delivery for curation of all significant paleontological resource materials encountered and collected during project construction. The project owner shall be responsible for paying any curation fees charged by the museum for fossils collected and curated as a result of paleontological mitigation.

Verification: The project owner shall maintain in his/her compliance file copies of signed contracts or agreements with the designated PRS and other qualified research specialists. The project owner shall maintain these files for a period of three years after project completion and approval of the CPM-approved paleontological resource report (see Condition of Certification **PAL-7**). A copy of the letter of transmittal submitting the fossils to the curating institution shall be provided to the CPM.

PAL-7 The project owner shall ensure preparation of a Paleontological Resources Report (PRR) by the designated PRS. The PRR shall be prepared following completion of the ground-disturbing activities. The PRR shall include an analysis of the collected fossil materials and related information and submit it to the CPM for review and approval.

The report shall include, but is not limited to, a description and inventory of recovered fossil materials; a map showing the location of paleontological resources encountered; determinations of sensitivity and significance; and a statement by the PRS that project impacts to paleontological resources have been mitigated below the level of significance.

Verification: Within 90 days after completion of ground-disturbing activities, including landscaping, the project owner shall submit the PRR under confidential cover to the CPM.

Certification of Completion
Worker Environmental Awareness Program
Hydrogen Energy California Project (08-AFC-8)

This is to certify these individuals have completed a mandatory California Energy Commission-approved Worker Environmental Awareness Program (WEAP). The WEAP includes pertinent information on cultural, paleontological, and biological resources for all personnel (that is, construction supervisors, crews, and plant operators) working on site or at related facilities. By signing below, the participant indicates that he/she understands and shall abide by the guidelines set forth in the program materials. Include this completed form in the Monthly Compliance Report.

No.	Employee Name	Title/Company	Signature
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Cultural Trainer: ______________ Signature:___________________ Date: ___/___/____

PaleoTrainer: _______________ Signature:___________________ Date: ___/___/____

Biological Trainer: ______________Signature:________________ Date:___/___/__

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POWER PLANT EFFICIENCY

Shahab Khoshmashrab

SUMMARY OF CONCLUSIONS

The gasification block, while operating on hydrogen-rich gas, would feed a 390-megawatt (MW) (gross output) combined cycle plant at a fuel efficiency of up to 49% lower heating value (LHV) at annual average ambient conditions (HECA 2009a, AFC Table 2-11). While operating on natural gas, this gasification combined cycle plant would produce approximately 330 MW (gross output) of electricity at a fuel efficiency of up to 55% LHV at annual average ambient conditions (HECA 2009a, AFC Table 2-11). The net electrical generation output from hydrogen-rich gas fuel would provide approximately 250 MW of low-carbon baseload power to the grid. While it would consume large amounts of energy, it would do so in the most efficient manner practicable to meet the project objectives (see discussion in **PROJECT ENERGY REQUIREMENTS AND ENERGY USE EFFICIENCY**, below). It would not create significant adverse effects on energy supplies or resources and would not consume energy in a wasteful or inefficient manner. No energy standards apply to this project. Staff therefore concludes that this project would present no significant adverse impacts on energy resources.

INTRODUCTION

One of the responsibilities of the California Energy Commission (Energy Commission) is to make findings on whether the energy use by a power plant, including the proposed HECA project, would result in significant adverse impacts on the environment, as defined in the California Environmental Quality Act (CEQA). If the Energy Commission finds that the HECA project's energy consumption creates a significant adverse impact, it must further determine if feasible mitigation measures could eliminate or minimize that impact. In this analysis, staff addresses the inefficient and unnecessary consumption of energy.

In order to support the Energy Commission's findings, this analysis will:

- examine whether the facility would likely present any adverse impacts upon energy resources;
- examine whether these adverse impacts are significant; and if so,
- examine whether feasible mitigation measures could eliminate those adverse impacts or reduce them to a level of insignificance.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

No federal, state, or local/county laws, ordinances, regulations, and standards (LORS) apply to the efficiency of this project.

SETTING

Hydrogen Energy International, the applicant, proposes to build and operate the HECA project, consisting of a gasification block, a combined cycle power train, and an auxiliary simple cycle power train. The gasification block would use feedstock to produce a synthesis gas that would be processed and purified to produce hydrogen-rich gas, which would be used to fuel the combustion turbine for electric power generation. The combined cycle power train would provide 250 MW (net output) baseload power to the electric grid.

Heat from the steam turbine generator, the combustion turbine generator, and other power block equipment would be rejected through the evaporative cooling tower. The gasification block would use feedstock to produce a synthesis gas that would be processed and purified to produce hydrogen-rich gas, which would be used to fuel the combustion turbines for electric power generation. The applicant plans to perform 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, and plant wide operational reliability test (HEI 2009c, AFC § 2.5.4.4).

Natural gas is required to startup the combined cycle train's combustion turbine generator to the load required to accept hydrogen-rich fuel, to operate the simple cycle's combustion turbine generator, and to startup the gasifier. Natural gas serves as a backup fuel to allow electric power generation to continue when hydrogen-rich fuel is not available due to, for example, maintenance of the gasifier unit. Two large natural gas pipeline systems (from PG&E and Southern California Gas Company [SoCalGas]) appear to be potentially suited to supply natural gas to the project. The distance between the main pipeline system headers and the project site is approximately seven miles (HEI 2009c, AFC § 2.1.8.3).

ASSESSMENT OF IMPACTS

METHOD AND THRESHOLD FOR DETERMINING THE SIGNIFICANCE OF ENERGY RESOURCES

CEQA guidelines state that the environmental analysis "…shall describe feasible measures which could minimize significant adverse impacts, including where relevant, inefficient and unnecessary consumption of energy" (Title 14 CCR §15126.4[a][1]). Appendix F of the guidelines further suggests consideration of such factors as the project's energy requirements and energy use efficiency; its effects on local and regional energy supplies and energy resources; its requirements for additional energy supply capacity; its compliance with existing energy standards; and any alternatives that could reduce the wasteful, inefficient, and unnecessary consumption of energy (Title 14, CCR §15000 et seq., Appendix F).

The inefficient and unnecessary consumption of energy, in the form of non-renewable fuels such as natural gas and oil, constitutes an adverse environmental impact. An adverse impact can be considered significant if it results in:

- Adverse effects on local and regional energy supplies and energy resources;

- A requirement for additional energy supply capacity;
- Noncompliance with existing energy standards; or
- The wasteful, inefficient, and unnecessary consumption of fuel or energy.

PROJECT ENERGY REQUIREMENTS AND ENERGY USE EFFICIENCY

Any power plant large enough to fall under Energy Commission siting jurisdiction (50 MW or greater) will, by definition, consume large amounts of energy. Under normal conditions, the HECA project would burn natural gas at a maximum rate of approximately 3,320 million British thermal units (MMBtu) per hour, HHV, during peak load operation (HEI 2009c, AFC Table 2-11). This is a substantial rate of energy consumption that could potentially impact energy supplies. However, because natural gas would be primarily consumed only during startup of the combined cycle unit, and to operate the simple cycle peaking unit, the overall annual rate of natural gas consumption would not be as substantial as a typical natural-gas fired power plant consuming only natural gas.

Under expected project conditions, electricity would be generated by the HECA project's combined cycle train at an efficiency of approximately 49% LHV, while burning hydrogen-rich gas, and at an efficiency of approximately 55% LHV, while burning natural gas. These efficiency levels compare favorably with the average fuel efficiencies of other combined cycle power plants for each respective fuel source. Under expected project conditions, electricity would be generated by the HECA project's simple cycle train at an efficiency of approximately 46% LHV. This efficiency level compares favorably with the average fuel efficiency of other simple cycle power plants employing the LMS100 machine.

As explained above, the combined cycle train, while consuming hydrogen-rich gas, would produce an average of 390 MW at 49% efficiency. Approximately 142 MW of the power produced will be used for hydrogen generation and CO2 sequestration processes, and for other auxiliary uses (HEI 2009c, AFC Table 2-11, 3rd column). This is a substantial amount of power (energy in form of electricity). However, it is important to point out that the project's objective is not only to sell electricity through the power grid, but also to utilize the energy stored in recyclable waste (oil by-product) and to implement the CO2 sequestration process to enhance oil recovery. The loss of energy (in the form of electricity) consumed for these processes would be offset by the benefit of utilizing the stored energy in a recyclable energy source (industrial waste as opposed to a depleting source, such as natural gas) and by the benefit of increased oil production from the oil-recovery enhancement process. Thus, staff believes this project would not result in wasteful, inefficient, and unnecessary consumption of fuel or energy.

ADVERSE EFFECTS ON ENERGY SUPPLIES AND RESOURCES

The applicant has described its sources of natural gas to operate the project (HEI 2009c, AFC § 2.1.8.3). Two large natural gas pipeline systems (from PG&E and Southern California Gas Company [SoCalGas]) appear to be potentially suited to supply natural gas to the project. The PG&E and SoCalGas systems draw from extensive supplies originating in the southwest and in Canada, and are capable of delivering the gas that the HECA would require to operate. This natural gas supply is a reliable source of natural gas for this project. It therefore appears unlikely that the project would create a substantial impact on natural gas supplies.

ADDITIONAL ENERGY SUPPLY REQUIREMENTS

Natural gas fuel would be supplied to the project by PG&E and SoCalGas (HEI 2009c, AFC § 2.1.8.3). There appears to be little likelihood that the HECA would require additional capacity.

The amount of diesel fuel to be consumed by trucks and trains transporting fuel, feedstocks, byproducts, waste materials, and other materials to and from the project site are estimated to be 4,841,608 gallons per year for the trucks and 264,029 gallons per year for the trains (URS 2010a, Data Response 80), a total of approximately 5 million gallons per year. California's diesel fuel supply system is extensive. For example, the available diesel fuel supply in California for the year 2009 was reported to be approximately 5,000 million gallons (CEC 2010h). Therefore, the above figure anticipated for the project would have a less than significant impact on the regional supply capacity.

COMPLIANCE WITH ENERGY STANDARDS

No standards apply to the efficiency of the HECA project or other non-cogeneration projects.

ALTERNATIVES TO REDUCE WASTEFUL, INEFFICIENT, AND UNNECESSARY ENERGY CONSUMPTION

The HECA project could be deemed to create significant adverse impacts on energy resources if alternatives were available that could reduce the project's fuel use. The evaluation of alternatives to the project (that could reduce wasteful, inefficient, or unnecessary energy consumption) first requires the examination of the project's energy consumption. Project fuel efficiency, and therefore its rate of energy consumption, is determined by both the configuration of the power producing system and the selection of equipment used to generate its power.

Project Configuration

The plant would employ one General Electric Frame 7FB combustion gas turbine generator which would consume natural gas for startup and hydrogen-rich gas for normal operation in a combined cycle configuration, equipped with an evaporative inlet air cooling system; one 3-pressure heat recovery steam generator (HRSG) equipped with duct burner; and one condensing steam turbine generator (HECA 2009a, AFC §§ 2.3.1, 2.5.1). Electricity would be generated by the gas turbine and by the steam turbine operating on heat energy recovered from the gas turbine's exhaust. By recovering this heat, which would otherwise be lost up the exhaust stack, the efficiency of any combined cycle power plant is increased from that of either a gas turbine or a steam turbine operating alone. This configuration is well suited to the large, steady loads met by a baseload plant that generates energy efficiently over long periods of time.

The project would also employ one auxiliary natural gas-fired General Electric LMS100 combustion gas turbine generator in a simple cycle configuration, operating independently from the rest of the facility, equipped with an evaporative inlet air cooling system (HECA 2009a, AFC § 2.3.3). Although the efficiency of a simple cycle train is lower than that of a combined cycle train, because the intent of a simple cycle train is to provide peaking and load following services, as envisioned for this project, staff believes the inclusion of the simple cycle train as a part of the project is reasonable.

The applicant plans to perform 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, and plant wide operational reliability test. This will help to ensure a smooth commissioning and startup process.

Equipment Selection

The F-class of advanced gas turbine to be installed in the HECA project represents one of the most modern and efficient machines available. The applicant would install one GE Frame 7FB combustion gas turbine generator in a one-on-one combined cycle power train nominally rated at 280.3 MW (without duct firing) and 57.3% net plant efficiency LHV under International Organization for Standardization (ISO) conditions, when burning natural gas (GTW 2008) (ratings are not available for syngas fuel).

One possible alternative is the Siemens (formerly Westinghouse) SCC6-5000F, nominally rated in a one-on-one train combined cycle configuration at 295.7 (without duct firing) MW and 57.0% efficiency LHV at ISO conditions (GTW 2008).

Another alternative is the Alstom Power KA24, nominally rated in a one-on-one configuration at 278.9 MW (without duct firing) with an efficiency rating of 57.1% LHV at ISO conditions.

Any differences among the SCC6-5000F, the KA24 and the GE 7FB in actual operating efficiency would be insignificant. Selecting among these machines is thus based on other factors such as generating capacity, cost, commercial availability and experience, and the ability to meet air pollution limitations. Due to GE Frame 7F’s extensive commercial experience and GE’s experience in the gasification technology, staff believes the applicant’s selection of the GE’s gas turbine is reasonable.

Efficiency of Alternatives to the Project

The HECA project’s objectives include the efficient generation of electricity to help meet the future electrical power needs (HECA 2009a, AFC § 2.1.1).

Alternative Generating Technologies

Alternative generating technologies for the HECA project are considered in the AFC (HECA 2009a, AFC § 6.4.1). For purposes of this analysis, fossil fuels, hydroelectric, solar, wind, and geothermal technologies are all considered.

The applicant selected the IGCC (Integrated Gasification Combined Cycle) technology because of its unique ability to produce low-carbon, hydrogen-rich fuel for baseload power generation.

Given the project objectives, location, and air pollution control requirements, and the commercial experience of the above technologies, staff agrees with the applicant that the technologies chosen for this project are feasible.

Natural Gas-Burning Technologies

Fuel consumption is one of the most important economic factors in selecting an electric generator; fuel typically accounts for over two-thirds of the total operating costs of a fossil fuel-fired power plant (Power 1994). Under a competitive power market system, where operating costs are critical in determining the competitiveness and profitability of a power plant, the plant owner is strongly motivated to purchase fuel-efficient machinery. Even though the consumption of natural gas for this project would be limited to the startup of the combined cycle train's combustion turbine generator, the operation of the simple cycle's combustion turbine generator, and the startup of the gasifier, staff has analyzed alternative natural gas-burning technologies in the following paragraphs.

Modern gas turbines represent the most fuel-efficient electric generating technology available today. Currently available large combustion turbine models can be grouped into three categories: conventional, advanced, and next generation. Advanced combustion turbines, chosen by the applicant, have advantages for the HECA project. Their higher firing temperatures offer higher efficiencies than conventional turbines. They offer proven technology with numerous installations and extensive run times in commercial operations. Emission levels are also proven, and guaranteed emission levels have been reduced based upon the operational experience and design optimization of their manufacturers.

One possible alternative to an advanced F-class gas turbine is the next generation G-class machine, such as the Siemens-Westinghouse 501G gas turbine generator, which uses partial steam cooling to allow slightly higher temperatures, yielding slightly greater efficiency. In actual operation, one would expect to see the difference in efficiency diminish, since larger-capacity G-class turbines run at less than optimum (full) output more frequently than smaller-capacity F-class turbines. (Gas turbine efficiency drops rapidly at less than full load.). Given the minor efficiency improvement promised by the G-class turbine, and since this machine would have to operate at less than optimum baseload efficiency in order to meet the project load capacity requirements, staff believes the applicant's selection of the F-class machine over the G-class machine is reasonable.

Another possible alternative to the F-class advanced gas turbine is an H-class next generation machine with a claimed fuel efficiency of 60% LHV at ISO conditions. This high efficiency is achieved through a higher pressure ratio and firing temperature, made possible by cooling the initial turbine stages with steam instead of air. This first Frame 7H application has only recently completed commissioning at the Inland Empire Energy Center in Riverside County, California. Given the lack of commercial experience with this machine and the project load requirements, staff agrees with the applicant's decision to use F-class machines.

Also, among the above technologies mentioned, apparently only Frame 7F gas turbine technology has been employed in other IGCC facilities. Both Tampa Electric and Duke Wabash IGCC facilities in Indiana have been operating the 7F gas turbine on syngas over the last 15 years.

Thus, given the lack of commercial experience with the G-class and H-class machines in an IGCC configuration and the project load requirements, staff agrees with the applicant's decision to use F-class machines.

Staff concludes that the selected project configurations (IGCC and simple cycle) and generating equipment (F-class gas turbine) represent the most efficient feasible combination for satisfying the project's objectives. There are no alternatives that would significantly reduce energy consumption while satisfying the project's objectives of producing low-carbon, hydrogen-rich fuel for baseload power generation and producing peaking power.

Staff, therefore, believes that the HECA project would not constitute a significant adverse impact on energy resources.

CUMULATIVE IMPACTS

No nearby projects have been identified that could potentially combine with the HECA project to create cumulative impacts on fuel resources. The PG&E and Southern California Gas Company natural gas supply systems are adequate to supply the HECA project without adversely impacting their other customers. There will be adequate petcoke and coal supplies to meet the project's needs; see the section of this document entitled **Power Plant Reliability**.

Staff believes that the construction and operation of the project would not create indirect impacts (in the form of additional fuel consumption), that would not have otherwise occurred without this project. Older, less efficient power plants consume more natural gas than new, more efficient plants such as the HECA project. Natural gas is burned by the most competitive power plants on the spot market, and the most efficient plants run the most frequently. The high efficiency of the proposed HECA project should allow it to compete favorably, run at high capacity, and replace less efficient power generating plants. Additionally, the project would consume natural gas for startup and, normally, hydrogen-rich gas for operation. The project would therefore not adversely impact the cumulative amount of natural gas consumed for power generation.

NOTEWORTHY PUBLIC BENEFITS

The project will provide both, baseload and peaking power to help meet the regional electricity demands, by doing so in a fuel-efficient manner, through installing the most modern gas turbine generators available.

CONCLUSIONS AND RECOMMENDATIONS

The gasification block would feed a 390-megawatt (MW) (gross output) combined cycle plant while operating on hydrogen-rich gas at a fuel efficiency of up to 49% lower heating value (LHV) at annual average ambient conditions. This gasification combined cycle plant would produce 329 MW (gross output) of electricity while operating on natural gas at a fuel efficiency of up to 55% LHV at annual average ambient conditions. The net electrical generation output from the project would provide approximately 250 MW of low-carbon baseload power to the grid. While it would consume large amounts of energy, it would do so in the most efficient manner practicable to meet the project objectives (see discussion in **PROJECT ENERGY REQUIREMENTS AND ENERGY USE EFFICIENCY**, above). It would not create significant adverse effects on energy supplies or resources, would not require additional sources of energy supply, and would not consume energy in a wasteful or inefficient manner. No energy standards apply to the project. Staff therefore concludes that the project would present no significant adverse impacts upon energy resources.

No cumulative impacts on energy resources are likely. Facility closure would not likely present significant impacts on electric system efficiency.

PROPOSED CONDITIONS OF CERTIFICATION

No conditions of certification are proposed.

REFERENCES

CEC 2010h – California Energy Commission; email communication between Shahab Khoshmashrab and Andre Freeman, Associate Energy Specialist, California

GTW 2008 – Gas Turbine World 2008 Performance Specs. 25th Edition, 2008.

HECA 2009a - Hydrogen Energy International, LLC /J. Briggs (tn 51735). Revised Application for Certification, dated 05/28/09. Submitted to CEC/Docket Unit on 05/28/09.

Power 1994. “Operating and Maintaining IPP/Cogen Facilities” Power, September 1994, p. 14.

URS 2010a - URS/D. Shileikis (tn 54762). Applicant's Response to Energy Commission Data Requests Set One (#1 through 132), dated 1/8/10. Submitted to CEC/Docket Unit on 1/8/10.

POWER PLANT RELIABILITY

Shahab Khoshmashrab

SUMMARY OF CONCLUSIONS

Hydrogen Energy International, the applicant, predicts an equivalent availability factor of at least 90% for the project, which staff believes is achievable. Based on a review of the proposal, staff concludes that Hydrogen Energy California (HECA) project would be built and would operate in a manner consistent with industry norms for reliable operation. This should provide an adequate level of reliability. No conditions of certification are proposed.

INTRODUCTION

In this analysis, California Energy Commission (Energy Commission) staff addresses the reliability issues of the project to determine if the power plant is likely to be built in accordance with typical industry norms for reliable power generation. Staff uses this level of reliability as a benchmark because it ensures that the resulting project would not be likely to degrade the overall reliability of the electric system it serves (see the **Setting** section, below).

The scope of this power plant reliability analysis covers:

- equipment availability;
- plant maintainability;
- fuel and water availability; and
- power plant reliability in relation to natural hazards.

Staff examined the project design criteria to determine if the project is likely to be built in accordance with typical industry norms for reliable power generation. While the applicant has predicted an equivalent availability factor of at least 90% for the HECA project (see below), staff uses typical industry norms as a benchmark, rather than the applicant's projection, to evaluate the project's reliability.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

No federal, state, or local/county laws, ordinances, regulations, or standards (LORS) apply to the reliability of this project.

SETTING

In the restructured competitive electric power industry, the responsibility for maintaining system reliability falls largely to the state's control area operators, such as the California Independent System Operator (California ISO), which purchase, dispatch, and sell electricity throughout the state. How the California ISO and other control area operators ensure system reliability is an ongoing process; protocols are still being developed and put in place to provide sufficient reliability in the competitive market system. "Must-run" power purchase agreements and “participating generator” agreements are two mechanisms that ensure an adequate supply of reliable power.

The California ISO also requires that power plants selling ancillary services, as well as those holding reliability must-run contracts, fulfill certain requirements, including:

- filing periodic reports on plant reliability;
- reporting all outages and their causes; and
- scheduling all planned maintenance outages with the California ISO.

The California ISO’s mechanisms to ensure adequate power plant reliability have apparently been developed with the assumption that individual power plants competing to sell power into the system will exhibit reliability levels similar to those of power plants of past decades.

As part of its plan to provide needed reliability, the applicant proposes to operate the 390 megawatt (MW) (average gross output) HECA project, consisting of a gasification block, a combined cycle power train, and an auxiliary simple cycle power train. The gasification block would use feedstock to produce a synthesis gas that would be processed and purified to produce hydrogen-rich gas, which would be used to fuel the combustion turbines for electric power generation.

The project is expected to achieve an equivalent availability factor of at least 90% (HECA 2009a, AFC §2.8.2). The project would be expected to operate at a maximum of 89% annual capacity factor (HECA 2009a, AFC Table 2-27).

ASSESSMENT OF IMPACTS

METHOD FOR DETERMINING RELIABILITY

The Energy Commission must make findings as to how the project is designed, sited, and operated in order to ensure its safe and reliable operation (Title 20, CCR §1752[c]). Staff takes the approach that a project is acceptable if it does not degrade the reliability of the utility system to which it is connected. This is likely the case if a project is at least as reliable as other power plants on that system.

The availability factor of a power plant is the percentage of time it is available to generate power; both planned and unplanned outages subtract from this availability. Measures of power plant reliability are based upon both the plant’s actual ability to generate power when it is considered to be available, and upon starting failures and unplanned (or forced) outages. For practical purposes, reliability can be considered a combination of these two industry measures, making a reliable power plant one that is available when called upon to operate. Power plant systems must be able to operate for extended periods without shutting down for maintenance or repairs. Achieving this reliability requires adequate levels of equipment availability, plant maintainability with scheduled maintenance outages, fuel and water availability, and resistance to natural hazards. Staff examines these factors for a project and compares them to industry norms. If they compare favorably for this project, staff will then conclude that the HECA project would be as reliable as other power plants on the electric system and would not degrade system reliability.

EQUIPMENT AVAILABILITY

Equipment availability would be ensured by adopting appropriate quality assurance/quality control (QA/QC) programs during the design, procurement, construction, and operation of the plant, and by providing for the adequate maintenance and repair of the equipment and systems discussed below.

General Electric (GE) gasification technology for solid fuels has been demonstrated in many commercial applications worldwide. The GE gasification technology for 100% petcoke feed is currently used in the Valero Refinery in Delaware and the Coffeyville Resources Ammonia Plant in Kansas. The GE gasification technology for mixed petcoke and coal operation has been demonstrated at Tampa Electric's integrated gasification combined cycle (IGCC) plant in Florida and in different chemical plants in China.

The gas turbine technology employed in this project is the GE Frame 7FB. Both Tampa Electric and Duke Wabash IGCC facilities in Indiana have been operating the 7FA gas turbine, which is substantially similar to the 7FB, on syngas (the direct end of the gasification process) over the last 15 years. The remaining components of the power block (Heat Recovery Steam Generator (HRSG), steam turbine, and generator) will employ conventional proven technology.

Most existing solid feedstock IGCC plants do not have spare gasifiers. The project incorporates one complete spare gasification train. Each gasification train will be shut down on a planned basis to perform the required maintenance. Because of the proactive scheduled maintenance, it is expected that unplanned outage of the gasification train can be minimized.

Quality Control Program

The applicant describes a quality assurance/quality control program for managing the useful life status of project components (HECA 2009a, AFC §2.8.2) that is typical of the power industry. Equipment would be purchased from qualified suppliers based on technical and commercial evaluations. Suppliers' personnel, production capability, past performance, QA programs and quality history would be evaluated. The project owner would perform receipt inspections, test components, and administer independent testing contracts. Staff expects that implementation of this program would result in standard reliability of design and construction. To ensure this implementation, staff has proposed appropriate conditions of certification in the section of this document entitled **Facility Design**.

PLANT MAINTAINABILITY

Equipment Redundancy

A generating facility operating in base-load mode for long periods of time must be capable of being maintained while operating. A typical approach to this is to provide redundant examples of those pieces of equipment that are most likely to require service or repair.

The applicant plans to provide an appropriate redundancy of function for the project (HECA 2009a, AFC §§ 2.3.2, 2.4.17, 2.5, 2.5.1, 2.8.2). Because the project consists of two combustion turbine generators, operating in parallel as independent equipment trains, it is inherently reliable. A single equipment failure cannot disable more than one train, allowing the plant to continue to generate power at reduced output. All plant ancillary systems are also designed with adequate redundancy to ensure their continued operation if equipment fails. For example, the plant's distributed control system would be built with typical redundancy.

Feedstock storage will include 15,000 tons of active storage (sufficient for three to 5 days of operation) and at least 30 days inactive emergency storage based on the maximum plant production rate. Active storage will include three 5,000-ton entirely enclosed cone-bottom silos, with one or more silos dedicated for each type of feedstock (depending on plant operation). An inactive storage pile will be provided on site (HECA 2009a, AFC § 2.1.8.1).

The project incorporates one complete spare gasification train. Each gasification train will be shut down on a planned basis to perform the required maintenance.

Staff believes that the project's proposed equipment redundancy would be sufficient for its reliable operation.

Maintenance Program

Equipment manufacturers provide maintenance recommendations for their products, and the applicant is expected to base the project's maintenance program on those recommendations. The program would encompass both preventive and predictive maintenance techniques. Maintenance outages would probably be planned for periods of low electricity demand. Staff expects that the project would be adequately maintained to ensure an acceptable level of reliability.

FUEL AND WATER AVAILABILITY

The long-term availability of fuel and of water for cooling or process use is necessary to ensure the reliability of any power plant. The need for reliable sources of fuel and water is obvious; lacking long-term availability of either source, the service life of the plant could be curtailed, threatening both the power supply and the economic viability of the plant.

Fuel Availability

The primary feedstock for the gasification plant is petcoke. Petcoke would be supplied from refineries in the Los Angeles, Bakersfield, or other northern California areas, and/or other regional sources. The petcoke that will be used for the project is a by-product from the oil refining process which is predominantly exported overseas for use as a low-grade fuel (HEI 2009c, AFC § 2.1.8.1). Coal may also be blended, up to 75%, with petcoke to diversify the feedstock supply.

Transportation of petcoke and coal to the project will be by truck. Coal will be brought in-state by rail and loaded onto trucks at a nearby loading terminal. Petcoke and coal will be transported from the truck unloading system to the active storage silos (HECA 2009a, AFC § 2.1.8.1). The project expects to obtain its necessary coal supply from the Uinta Basin in Utah and Colorado.

Approximately 16,350 tons per day (tpd) (6.0 million tons per year [tpy]) of fuel grade petcoke are produced by major California refineries, including British Petroleum. Five of these refineries are located in the Los Angeles area, three are in the San Francisco area, and two are in Central California. At steady-state operation feeding 100% petcoke, the project would consume about 17% of this total production (approximately 2,820 tpd, or 1.0 million tpy).

To maximize the number of potential fuel suppliers, the project would be designed to accept a range of feedstock blends. It would incorporate a fluxant injection system to allow operation on 100% petcoke, but can also operate on a blend of as much as 75% thermal input coal, with petcoke.

Staff agrees with the applicant's claim that there will be adequate petcoke and coal supplies to meet the project's needs.

Natural gas is required to startup the combined cycle train's combustion turbine generator to the load required to accept hydrogen-rich fuel, and to operate the simple cycle's combustion turbine generator. Natural gas serves as a backup fuel to allow electric power generation to continue when hydrogen-rich fuel is not available due to, for example, maintenance of the gasifier unit. Two large natural gas pipeline systems (from PG&E and Southern California Gas Company [SoCalGas]) appear to be potentially suited to supply natural gas to the project. The distance between the main pipeline system headers and the project site is approximately seven miles (HEI 2009c, AFC § 2.1.8.3). The historical pipeline pressures for the PG&E pipeline indicate that the natural gas pressure should be adequate virtually all of the time, and would have no impact on the HECA project generating reliability. The historical pipeline pressures for the SoCalGas pipeline indicate that the HECA project generating reliability could be theoretically reduced by 0.3% due to insufficient natural gas pressure, but staff believes a 0.3% reduction in reliability would have a negligible impact on operability.

PG&E and SoCalGas's natural gas systems represent resources of considerable capacity and offer access to adequate supplies of gas from the Southwest, the Rocky Mountains, and Canada. Staff agrees with the applicant's claim that there will be adequate natural gas supply and pipeline capacity to meet the project's needs.

Water Supply Reliability

The HECA project would utilize brackish groundwater supplied from the Buena Vista Water Storage District for the project's process and evaporative cooling uses. 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. The potable water supply pipeline will be approximately 7 miles in length (HEI 2009c, AFC §§ 2.1.6, 2.1.8.4). Staff believes these sources represent a reliable supply of water for the project. For further discussion of water supply, see the **Soil and Water Resources** section of this document.

POWER PLANT RELIABILITY IN RELATION TO NATURAL HAZARDS

Natural forces can threaten the reliable operation of a power plant. High winds, tsunamis (tidal waves), and seiches (waves in inland bodies of water) are not likely to present hazards for this project, but seismic shaking (earthquakes) and flooding could present credible threats to the project's reliable operation.

Seismic Shaking

The site lies within an active seismic zone; see the "Faulting and Seismicity" portion of the **Geology and Paleontology** section of this document. The project would be designed and constructed to the latest appropriate LORS (HECA 2009a, AFC Appendix B). Compliance with current seismic design LORS represents an upgrading of performance during seismic shaking compared to older facilities since these LORS have been periodically and continually upgraded. Because it would be built to the latest seismic design LORS, this project would likely perform at least as well as, and perhaps better than, existing plants in the electric power system. Staff has proposed conditions of certification to ensure this; see the section of this document entitled **Facility Design**. In light of the general historical performance of California power plants and the electrical system in seismic events, staff has no special concerns with the power plant's functional reliability during seismic events.

Flooding

General site elevation varies slightly from the high point grade elevation of 291 feet above mean sea level. This site is not within the 100-year floodplain (HECA 2009a, AFC § 2.7.1, Table 2-2).

The plant site would be graded to promote drainage to prevent onsite flooding and minimize the potential for flooding to neighboring areas. Grading and project construction would be performed in accordance with the applicable grading standards and codes (see the section of this document entitled **Facility Design)**.

Staff believes there are no special concerns with power plant functional reliability due to flooding. For further discussion, see **Soil and Water Resources**, and **Geology and Paleontology**.

COMPARISON WITH EXISTING FACILITIES

Industry statistics for availability factors (as well as other related reliability data) are maintained by the North American Electric Reliability Corporation (NERC). NERC regularly polls North American utility companies on their project reliability through its Generating Availability Data System, and periodically summarizes and publishes those statistics on the Internet [http://www.nerc.com]. The NERC reported the following generating unit statistics for the years 2004 through 2008 (NERC 2008):

For combined cycle units (50 MW and larger):

Equivalent Availability Factor = 87.01%

For gas turbine units only (simple cycle) (50 MW and larger):

Equivalent Availability Factor = 91.82%

The project's gas turbines have been on the market for several years now and are expected to exhibit typically high availability. The applicant's expectation of an annual availability factor of at least 90% (HECA 2009a, AFC § 2.8.2) appears reasonable when compared with NERC figures for similar plants throughout North America (see above). In fact, these machines can well be expected to outperform the fleet of various (mostly older and smaller) gas turbines that make up NERC statistics.

Both petcoke gasification and gas purification with carbon capture are proven technologies, operating at commercial scale within the United States and around the world. Three IGCC plants are operating in the United States with 100% petcoke or petcoke/coal blends feedstocks (TECO/Tampa, SG-Solutions/Wabash, Valero/Delaware), with an additional 12 plants operating worldwide.

The applicant's estimate of plant availability, therefore, appears to be realistic. Stated procedures for assuring the design, procurement, and construction of a reliable power plant appear to be consistent with industry norms, and staff believes they are likely to ultimately produce an adequately reliable plant.

NOTEWORTHY PROJECT BENEFITS

This project would enhance power supply reliability in the California electricity market by meeting the state's growing energy demand, contributing to electricity reserves in the region, and providing operating flexibility (that is, the ability to start up, shut down, turn down, and provide load following and spinning reserve).

CONCLUSION

The applicant predicts an equivalent availability factor of at least 90%, which staff believes is achievable. Based on a review of the proposal, staff concludes that the plant would be built and operated in a manner consistent with industry norms for reliable operation. This should provide an adequate level of reliability. No conditions of certification are proposed.

PROPOSED CONDITIONS OF CERTIFICATION

No conditions of certification are proposed.

REFERENCES

HEI 2009c - Hydrogen Energy International, LLC /J. Briggs (tn 51735). Revised Application for Certification, dated 05/28/09. Submitted to CEC/Docket Unit on 05/28/09.

NERC 2008 — North American Electric Reliability Council. 2004–2008 Generating Availability Report.

TRANSMISSION SYSTEM ENGINEERING

Sudath Edirisuriya and Mark Hesters

SUMMARY OF CONCLUSIONS

The proposed Hydrogen Energy California Project (HECP) outlet lines and termination are acceptable and would comply with all applicable laws, ordinances, regulations, and standards (LORS). No additional new transmission facilities that would require a California Environmental Quality Act (CEQA) review other than those proposed by the applicant are needed for the interconnection of the HECP project.

- The interconnection of the project would require a new onsite breaker and-a-half, 230kV, 63kA project switchyard and modification of the existing 230kV Midway substation to terminate the generator tie lines. The modification of the Midway substation would occur outside the fence line of the existing substation and would trigger CEQA review.
- The Transition Cluster Phase I Transmission Interconnection Study Report (Phase I Study) for the HECP identified several overloads under both normal and contingency conditions. The mitigation for these overloads could require reconductoring, congestion management or Remedial Action Schemes. It appears that, according to the Phase I Study, the HECP is not responsible for the overloads and thus the mitigation measures while necessary for the cluster are not a reasonably foreseeable consequence of the HECP.
- The reliable interconnection of the HECP would require rerating the Midway transformer bank and installing a Special Protection System (SPS) at Midway substation. The SPS installation would occur within the existing Midway substation and would not trigger CEQA.

Staff has not received the complete Phase I Study. Without the complete study with the associated appendices it is not possible to determine whether what types of mitigation measures are required specifically for the interconnection of the HECP, many of the necessary details are in included only in the study appendices. The Transition Cluster Phase II Interconnection Study Report (Phase II Study) for the HECP is scheduled to be issued by early July, 2010, staff expects to rely on the Phase II Study its final analysis.

STAFF ANALYSIS

The Transmission System Engineering (TSE) analysis examines whether or not the facilities associated with the proposed interconnection conform to all applicable LORS required for safe and reliable electric power transmission. Additionally, under the CEQA, the Energy Commission must conduct an environmental review of the “whole of the action,” which may include facilities not licensed by the Energy Commission (California Code of Regulations, title 14, §15378). Therefore, the Energy Commission must identify the system impacts and necessary new or modified transmission facilities downstream of the proposed interconnection that are required for interconnection and represent the “whole of the action.

Commission Staff rely on the interconnecting authority for the analysis of impacts on the transmission grid as well as the identification and approval of required new or modified facilities downstream from the proposed interconnection required as mitigation measures. The proposed HECP would connect to the Pacific Gas and Electric (PG&E) 230kV transmission network and requires analysis by PG&E and approval of the California Independent System Operator (California ISO).

PACIFIC GAS & ELECTRIC'S ROLE

PG&E is responsible for ensuring electric system reliability in the PG&E system for addition of the proposed generating plant. PG&E will provide the analysis and reports in their Transition Cluster Phase I and Phase II Studies for PG&E's Group 3 projects, and their approval for the facilities and changes required in the PG&E system for addition of the proposed transmission modifications.

CALIFORNIA ISO'S ROLE

The California ISO is responsible for ensuring electric system reliability for all participating transmission owners and is also responsible for developing the standards necessary to achieve system reliability. The California ISO is responsible for completing the studies of the PG&E system to ensure adequacy of the proposed transmission interconnection. The California ISO will determine the reliability impacts of the proposed transmission modifications on the PG&E transmission system in accordance with all applicable reliability criteria. According to the California ISO Tariff, the California ISO will determine the "Need" for transmission additions or upgrades downstream from the interconnection point to ensure reliability of the transmission grid. The California ISO will, therefore, review the Phase I Study performed by PG&E and/or any third party provide their analysis, conclusions and recommendations. Upon completion of the PG&E Phase II Study based on the expected January-2013 commercial operation date (COD) or current COD the California ISO would execute Large Generator Interconnection Agreement (LGIA) between the California ISO and the project owner. If necessary, the California ISO may provide written and verbal testimony on their findings at the Energy Commission hearings.

Laws, Ordinances, Regulations and Standards

- North American Electric Reliability Council (NERC) Planning Standards provide policies, standards, principles and guides to assure the adequacy and security of the electric transmission system. With regard to power flow and stability simulations, these Planning Standards are similar to WECC Criteria for Transmission System Contingency Performance. The NERC planning standards provide for acceptable system performance under normal and contingency conditions. The NERC planning standards apply not only to interconnected system operation but also to individual service areas (NERC 1998).
- Western Electric Coordinating Council (WECC) Reliability Criteria provide the performance standards used in assessing the reliability of the interconnected system. These Reliability Criteria require the continuity of service to loads as the first priority and preservation of interconnected operation as a secondary priority. The WECC Reliability Criteria include the Reliability Criteria for Transmission System

Planning, Power Supply Design Criteria, and Minimum Operating Reliability Criteria. Analysis of the WECC system is based to a large degree on WECC Section 4 “Criteria for Transmission System Contingency Performance” which requires that the results of power flow and stability simulations verify established performance levels. Performance levels are defined by specifying the allowable variations in voltage, frequency and loading that may occur on systems other than the one in which a disturbance originated. Levels of performance range from no significant adverse effect outside a system area during a minor disturbance (loss of load or facility loading outside emergency limits) to a performance level that only seeks to prevent system cascading and the subsequent blackout of islanded areas. While controlled loss of generation, load, or system separation is permitted in extreme circumstances, their uncontrolled loss is not permitted (WECC 1998).

- California Public Utilities Commission (CPUC) General Order 95 (GO-95), “Rules for Overhead Electric Line Construction,” formulates uniform requirements for construction of overhead lines. Compliance with this order ensures adequate service and safety to persons engaged in the construction, maintenance, operation, or use of overhead electric lines and to the public in general.
- California Public Utilities Commission (CPUC) General Order 128 (GO-128), “Rules for Underground Electric Line Construction,” formulates uniform requirements for construction of underground lines. Compliance with this order ensures adequate service and safety to persons engaged in the construction, maintenance, operation, or use of underground electric lines and to the public in general.
- National Electric Safety Code 1999 provides electrical requirements for overhead and underground electric line construction and design.
- California ISO’s Reliability Criteria also provide policies, standards, principles, and guides to assure the adequacy and security of the electric transmission system. With regard to power flow and stability simulations, these Planning Standards are similar to WECC Criteria for Transmission System Contingency Performance and the NERC Planning Standards. The California ISO Reliability Criteria incorporate the WECC Criteria and NERC Planning Standards. However, the California ISO Reliability Criteria also provide some additional requirements that are not found in the WECC Criteria or the NERC Planning Standards. The California ISO Reliability Criteria apply to all existing and proposed facilities interconnecting to the California ISO controlled grid. It also applies when there are any impacts to the California ISO grid due to facilities interconnecting to adjacent controlled grids not operated by the California ISO.

PROJECT DESCRIPTION

The applicant has proposed to interconnect the 396 MW (net) Hydrogen Energy California project to the existing PG&E Midway substation via newly built 230kV double circuit. The interconnection application to the California ISO was for a 396 MW plant but for the Phase II study the project has been reduced to 250 MW. The planned operational date of the proposed project is January 2014. The HECP would consist of one General Electric (GE) combustion turbine generators (CTG-1 rated at 237 MW) and one GE steam turbine generator (rated at 174 MW). The generator auxiliary load would be 15 MW resulting in a maximum net output of 396 MW at an 85 percent power factor. CTG-1 and STG-1 generator would be connected to the low side of their generator step-up transformer through a gas insulated (SF6) breaker and a disconnect switch. The step-up transformer for the CTG-1 unit would be rated at 18/230 kV and 170/227/283 MVA and while that for the STG unit step-up transformer would be rated at 18/230 kV and 125/167/208 MVA. The high side of the two generator step up transformers would be connected to the HECP switchyard via 1200Amps disconnect switches. The proposed HECP 230kV, 63kA switchyard would be designed with four-bay, 5 positions, breaker and a half configuration. The HECP switchyard would be constructed with 3000Amps circuit breakers, disconnect switches, revenue metering equipments and other switching gear to allow delivery of HECP output to the Midway substation.

The applicant has proposed two alternative generator-tie line routes, both of which extend from the western edge of the project site to the north, and west to the north side of the substation. The power plant generator-tie lines are approximately 10 mile long, built on single tower double circuit, constructed with 1158 kcmil per phase ACSS conductors and are rated to carry the full capacity of the plant. The construction of the proposed generator tie lines would require 230kV, 110 foot tall, 75 steel poles and would built along the 150 foot right-of-way. Furthermore, the PG&E has proposed expanding and upgrading the existing 230kV Midway substation to terminate the generator-tie lines. The PG&E Midway substation work includes extension of 230kV bus work to facilitate two bays with breaker and half configuration with two line position to terminate the generator tie lines of the HECP. (HECP 2009b, section 2.3.6, page 31 and Figures 2-15, 16 and 17)

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

For the interconnection of a proposed generating unit or transmission facility to the grid, the interconnecting utility and the control area operator are responsible for ensuring grid reliability. For the HECP, PG&E and the California ISO are responsible for ensuring grid reliability.

The California ISO's generator interconnection study process is in transition from a serial process to an interconnection window cluster study process. The HECP was studied under the cluster process and the transmission reliability impacts of the proposed project are studied in the Phase I and Phase II Studies. The Phase I Study is similar to the former System Impact Study except it is now performed for a group of projects in the same geographical area of a utility that apply for interconnection in the same request window. The Phase II Study is performed after generators in each cluster meet specific milestones required to stay in the generator interconnection queue. The Phase II Study is then performed based on the number of generators left in each cluster.

The Phase I Study for projects in the transition cluster were conducted to determine the preferred and alternative generator interconnection methods and to identify any mitigation measures required to ensure system conformance with utility reliability criteria, NERC planning standards, WECC reliability criteria, and California ISO reliability criteria. Staff relies on the studies and any review conducted by the responsible agencies to determine the effect of the projects on the transmission grid and to identify any necessary downstream facilities or indirect project impacts required to bring the transmission network into compliance with applicable reliability standards (NERC2006, WECC 2006, California ISO 2002a, 2007a & 2009a).

The Phase I Study analyzes the grid with and without the generator or generators in a cluster under conditions specified in the planning standards and reliability criteria. The standards and criteria define the assumptions used in the study and establish the thresholds by which grid reliability is determined. The studies must analyze the impact of the projects for their proposed first year(s) of operation and thus are based on a forecast of loads, generation and transmission. Load forecasts are developed by the interconnected utility, which would be PG&E in this case. Generation and transmission forecasts are based on the interconnection queue. The studies are focused on thermal overloads, voltage deviations, system stability (excessive oscillations in generators and transmission system, voltage collapse, loss of loads or cascading outages), short circuit duties and substation evaluation

Under the new California ISO LGIP, generators are able to choose between either “full capacity” or “energy only” depending on whether or not the generator wants to have the right to generate energy 24-hours per day. A generator that chooses the full capacity option will be required to pay for transmission network upgrades that are needed to allow the generator to operate under virtually any system conditions and as such could sign contracts that allowed them to provide capacity to utilities. Energy only generators would not pay for network transmission upgrades, and essentially would have access to as available transmission capacity, and would likely not be able to sign capacity contracts.

If the studies show that the interconnection of the project or cluster of projects causes the grid to be out of compliance with reliability standards, the study will then identify mitigation alternatives or ways in which the grid could be brought into compliance with reliability standards. If the interconnecting utility determines that the only feasible mitigation includes transmission modifications or additions which require CEQA review as part of the “whole of the action,” the Energy Commission must analyze those modifications or additions according to CEQA requirements. Where the Phase I Study identifies transmission modifications required for the reliable interconnection of a cluster of generators, staff will analyze the proposed generating project’s impact on individual reliability criteria violations to determine whether or not the identified mitigation measures are a reasonably foreseeable consequence of the proposed project.

SCOPE OF THE TRANSITION CLUSTER PHASE 1 INTERCONNECTION STUDY

The July 28, 2009, Transition Cluster Phase I Study was prepared by the California ISO in coordination with PG&E. The Phase I Study includes 7 queue generation projects in the PG&E San Lois Obispo/Kern area totaling 1295 MW net generation output, including the proposed 396 MW HECP. As of June 4, 2010 only five projects (890 MW) of the original 7 projects remain in the interconnection queue. Reducing the size of the cluster by 2 projects and 405 MW means the Phase I Study results may no longer provide a reasonable forecast of the reliability impacts of the proposed project or the other projects in the cluster.

CEQA requires the analysis of reasonably foreseeable consequences of proposed projects based on the best available information. The California ISO is the reliability authority for generator interconnections and its Phase I Study for the HECP provides the best available information on the reliability impacts of the proposed project. The revised 890 MW cluster will be analyzed in the Phase II Study and will provide a much better forecast of the reliability impacts of the HECP and its associated cluster of generators.

The Phase II Study for the Transition Cluster is currently scheduled to be completed by July of 2010 and will be incorporated into staff's analysis of the HECP. If the Phase II Study finds that the HECP and the remaining projects in its cluster would require the construction or upgrade of transmission facilities in order to maintain grid reliability, those transmission facilities would require a license from the California Public Utilities Commission or other permitting authority. Staff anticipates that future clusters will likely include fewer generators and the Phase I Studies which are not part of the Transition Cluster will provide a better forecast of the reasonably foreseeable transmission impacts of a specific generator.

TRANSITION CLUSTER STUDY RESULTS:

Detailed results of the Transitional Cluster Study are below. Where potential overloads are identified, mitigation is proposed that would eliminate the potential impact to reliability. Based on the information in the Phase I study, staff has never received the appendices for the study; the HECP appears to be responsible for few of the impacts that are identified for the cluster due to the HECP interconnection at the Midway substation. The Midway substation is a major transmission hub for California. However, staff did not receive the complete Phase I study with appendices; therefore staff was unable to completely analyze the potential transmission impacts and mitigation measures required for the reliable interconnection of the HECP. Staff expects that the applicant will submit the complete phase II study with appendices to finalize the mitigation measures in the Final Staff Assessment (FSA). The summary of impacts and mitigation measures below is for informational purposes only and does not represent the expected impacts of the HECP.

Summer Peak N-0 overloads:

Normal conditions (N-0); The power flow study projected that the Post-cluster projects would cause 8 new normal overloads under projected 2013 summer peak conditions. A summary of the transmission facility overloads is provided in Table 6-2-1, Page 9 of the Phase I Study.

> Recommended Mitigation: The recommended mitigation for these normal overloads is reconductoring the overloaded lines with higher capacity conductors or by generation curtailment (Special Protection Systems) and congestion management.

Summer Off-Peak N-0 overloads:

Normal conditions (N-0); The power flow study projected that the Post-cluster projects would cause 2 new normal overloads under projected 2013 summer off-peak conditions. A summary of the transmission facility overloads is provided in Table 6-2-1, Page 9 of the Phase I Study.

> Recommended Mitigation: The recommended mitigation for these normal overloads are congestion management and generation curtailment.

Summer Peak N-1 emergency overloads:

Contingency (N-1); The power flow study projected that the post-cluster projects would cause ten new N-1 overloads under the 2013 summer peak conditions. A summary of the transmission facility overloads is provided in table 6-2-2, page 10 of the Phase I study.

> Recommended Mitigation: The recommended methods to mitigate these N-1 overloads are reconductoring the overloaded lines with higher capacity conductors, generation curtailment (Special Protection Systems), implementing a short term emergency rating for the transformer banks at Midway substation and congestion management.

Summer Off-Peak N-1 emergency overloads:

Contingency (N-1); The power flow study projected that the Post-cluster projects would cause eleven new N-1 overloads under the 2013 Summer off–Peak conditions and exacerbates three pre-project N-1 overloads. A summary of the transmission facility overloads is provided in table 6-2-2, page 10 of the Phase I study.

> Recommended Mitigation: The recommended methods to mitigate these N-1 overloads are re-conductoring overload lines with higher capacity conductors, congestion management and obtain short term emergency rating of the conductors.

Summer Peak N-2 emergency overloads:

Contingency (N-2); The power flow study projected that the Post-cluster projects would cause eighteen new N-2 overloads under the 2013 Summer Peak conditions and exacerbates one pre-project N-2 overload. A summary of the transmission facility overloads is provided in table 6-2-3, page 11 of the Phase I study.

> Recommended Mitigation: The recommended methods to mitigate these N-2 overloads are re-conductoring overload lines with higher capacity conductors, implementing RAS to drop the overload transmission facilities, implementing SPS to curtail generation, obtain short term emergency ratings for overloaded transmission lines and congestion management.

Summer Off-Peak N-2 emergency overloads:

Contingency (N-2); The power flow study projected that the Post-cluster projects would cause fourteen new N-2 overloads under the 2013 Summer Peak conditions and exacerbates nine pre-project N-2 overload. A summary of the transmission facility overloads is provided in table 6-2-3, page 11 of the Phase I study.

Recommended Mitigation: The recommended methods to mitigate these N-2 overloads are re-conductoring overload lines with higher capacity conductors, implementing RAS to drop the overload transmission facilities, implementing SPS to curtail the generation, obtain short term emergency ratings of the transmission lines and congestion management.

Transient Stability Analysis results:

Stable and adequately damped transient stability performances were achieved following all of the outages simulated using both the pre-and post-cluster base cases. The power flow studies of N-1 and N-2 contingencies showed that the project would not cause voltage drops of 5 percent or more from the pre-project levels or cause the PG&E system to fail to meet applicable voltage criteria. No transient frequency criteria violations were observed for all the contingencies simulated. The transient stability study projected that the transmission system's performance relative to the applicable reliability guidelines would not be adversely affected by the Phase I projects due to selected disturbances.

Dynamic Stability Analysis results:

Dynamic stability studies were conducted using the 2013 summer peak full loop base cases to ensure that the transmission system remains in operating equilibrium following selected outages. The study concluded that the project would have no adverse impact on the stable operation of the transmission system. Dynamic studies indicate that the transmission system's transient stability performance would not be impacted by the project following the selected contingencies. (The study results are provided in the form of plots in Appendix F, Phase I study)

Short Circuit Study Results:

Short circuit studies were performed to determine the degree to which the addition of Phase I projects would increase fault duties at PG&E's substations, adjacent utility substations, and the other 115 kV, 230 kV and 500 kV busses within the study area. For the buses at which faults were simulated, the maximum three-phase and single-line-to-ground fault currents, both with and without the project, and information on the breaker duties at each location are summarized in Appendix H, short circuit study results, of the Phase I study report. The project would increase the existing fault duty at Midway substation's 230kV bus beyond its acceptable level (63 kA Three phase Line to Ground). Installing a new switching station with a Breaker and-a-half (BAHH) configuration, 5 Ohms reactor between existing Midway 230kV bus and a new 230kV bus at Midway substation are required in mitigating the midway 230kV bus fault duties. Additionally, initial breaker evaluation determined that the project causes one 230kV overstressed breaker at Gates substation (CB 262).This overstressed breaker should be replaced with higher interrupting capability breaker.

COMPLIANCE WITH LORS

The Phase I study indicates that the project interconnection would comply with NERC/WECC planning standards and California ISO reliability criteria. The applicant will design, build and operate the proposed 230 kV HECP switchyard and overhead generator transmission lines. The proposed modifications to the Midway substation will be done by PG&E outside the substation fenced yard. Therefore, it would trigger CEQA review. Staff concludes that assuming the proposed Conditions of Certification are met; the project will meet the requirements and standards of all applicable LORS.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff has received no comments to day on the Transmission System Engineering section.

CONCLUSIONS

The proposed Hydrogen Energy California Project (HECP) outlet lines and termination are acceptable and would comply with all applicable laws, ordinances, regulations, and standards (LORS). No additional new transmission facilities that would require a California Environmental Quality Act (CEQA) review other than those proposed by the applicant are needed for the interconnection of the HECP project.

- The interconnection of the project would require a new onsite breaker and-a-half, 230kV, 63kA project switchyard and modification of the existing 230kV Midway substation to terminate the generator tie lines. The modification of the Midway substation would occur outside the fence line of the existing substation and would trigger CEQA review.
- The Transition Cluster Phase I Transmission Interconnection Study Report (Phase I Study) for the HECP identified several overloads under both normal and contingency conditions. The mitigation for these overloads could require reconductoring, congestion management or Remedial Action Schemes. It appears that, according to the Phase I Study, the HECP is not responsible for the overloads and thus the mitigation measures while necessary for the cluster are not a reasonably foreseeable consequence of the HECP.
- The project is responsible in rerating the Midway transformer bank and installing the SPS at Midway substation. The SPS installation would occur within the existing Midway substation and would not trigger CEQA.

RECOMMENDATIONS

If the Commission approves the project, staff recommends the following Conditions of Certification to insure system reliability and conformance with LORS.

CONDITIONS OF CERTIFICATION FOR TSE

TSE-1 The project owner shall furnish to the CPM and to the CBO a schedule of transmission facility design submittals, a Master Drawing List, a Master Specifications List, and a Major Equipment and Structure List. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide designated packages to the CPM when requested.

<u>Verification:</u> At least 60 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of construction, the project owner shall submit the schedule, a Master Drawing List, and a Master Specifications List to the CBO and to the CPM. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see a list of major equipment in **Table 1: Major Equipment List** below). Additions and deletions shall be made to the table only with CPM and CBO approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

Table 1: Major Equipment List
Breakers
Step-up Transformer
Switchyard
Busses
Surge Arrestors
Disconnects
Take off facilities
Electrical Control Building
Switchyard Control Building
Transmission Pole/Tower
Grounding System

TSE-2 Prior to the start of construction the project owner shall assign an electrical engineer and at least one of each of the following to the project: A) a civil engineer; B) a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering; C) a design engineer, who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; or D) a mechanical engineer. (Business and Professions Code Sections 6704 et seq. require state registration to practice as a civil engineer or structural engineer in California.)

The tasks performed by the civil, mechanical, electrical or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (e.g., proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer. The civil, geotechnical or civil and design engineer assigned in conformance with Facility Design condition **GEN-5**, may be responsible for design and review of the TSE facilities.

The project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all engineers assigned to the project. If any one of the designated engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the

CBO's approval of the new engineer. This engineer shall be authorized to halt earthwork and to require changes; if site conditions are unsafe or do not conform with predicted conditions used as a basis for design of earthwork or foundations.

The electrical engineer shall:

1. Be responsible for the electrical design of the power plant switchyard, outlet and termination facilities; and

2. Sign and stamp electrical design drawings, plans, specifications, and calculations.

Verification: At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the names, qualifications and registration numbers of all the responsible engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the engineers within five days of the approval.

If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the name, qualifications, and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval. [3/12/03]

TSE-3 If any discrepancy in design and/or construction is discovered in any engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend corrective action. (1998 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall become a controlled document and shall be submitted to the CBO for review and approval and shall reference this condition of certification.

Verification: The project owner shall submit a copy of the CBO's approval ordisapproval of any corrective action taken to resolve a discrepancy to the CPM within 15 days of receipt. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action required obtaining the CBO's approval.

TSE-4 For the power plan switchyard, outlet line and termination, the project owner shall not begin any increment of construction until plans for that increment have been approved by the CBO. These plans, together with design changes and design change notices, shall remain on the site for one year after completion of construction. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS.The following activities shall be reported in the Monthly Compliance Report:

a. receipt or delay of major electrical equipment;

b. testing or energization of major electrical equipment; and

c. the number of electrical drawings approved, submitted for approval, and still to be submitted.

Verification: At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of each increment of construction, the project owner shall submit to the CBO for review and approval the final design plans, specifications and calculations for equipment and systems of the power plant switchyard, outlet line and termination, including a copy of the signed and stamped statement from the responsible electrical engineer attesting to compliance with the applicable LORS, and send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

TSE-5 The project owner shall ensure that the design, construction and operation of the proposed transmission facilities will conform to all applicable LORS, including the requirements listed below. The project owner shall submit the required number of copies of the design drawings and calculations as determined by the CBO.

a. The HECP will be interconnected to PG&E grid via a 230 kV, 1158 kcmil ACSS per phase , approximately 10 mile long double circuit. The proposed HECP switchyard will consist of four-bay, five position breaker and a half configuration.

b. The power plant outlet line shall meet or exceed the electrical, mechanical, civil and structural requirements of CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code and Regulations (Title 8), Articles 35, 36 and 37 of the “High Voltage Electric Safety Orders”, Cal-ISO standards, National Electric Code (NEC) and related industry standards.

c. Breakers and busses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.

d. Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner’s standards.

e. The project conductors shall be sized to accommodate the full output from the project.

f. Termination facilities shall comply with applicable PG&E interconnection standards.

g. The project owner shall provide to the CPM:

   i. Executed project owner and California ISO Large Generator Interconnection Agreement

Verification: At least 60 days prior to the start of construction of transmission facilities (or a lessor number of days mutually agree to by the project owner and CBO, the project owner shall submit to the CBO for approval:

a. Design drawings, specifications and calculations conforming with CPUC General Order 95 or NESC, Title 8, Articles 35, 36 and 37 of the “High Voltage Electric Safety Orders”, NEC, applicable interconnection standards and related industry standards, for the poles/towers, foundations, anchor bolts, conductors, grounding systems and major switchyard equipment.

b. For each element of the transmission facilities identified above, the submittal package to the CBO shall contain the design criteria, a discussion of the calculation method(s), a sample calculation based on “worst case conditions”[1] and a statement signed and sealed by the registered engineer in responsible charge, or other acceptable alternative verification, that the transmission element(s) will conform with CPUC General Order 95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the, “High Voltage Electric Safety Orders”, NEC, applicable interconnection standards, and related industry standards.

c. Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in responsible charge, a route map, and an engineering description of equipment and the configurations covered by requirements **TSE-5** a) through f) above.

d. The executed Large Generator Interconnection Agreement.

TSE-6 The project owner shall inform the CPM and CBO of any impending changes, which may not conform to the requirements **TSE-5** a) through f), and have not received CPM and CBO approval, and request approval to implement such changes. A detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change shall accompany the request. Construction involving changed equipment or substation configurations shall not begin without prior written approval of the changes by the CBO and the CPM.

Verification: At least 60 days prior to the construction of transmission facilities, the project owner shall inform the CBO and the CPM of any impending changes which may not conform to requirements of **TSE-5** and request approval to implement such changes.

[1] Worst case conditions for the foundations would include for instance, a dead-end or angle pole.

TSE-7 The project owner shall provide the following Notice to the California Independent System Operator (California ISO) prior to synchronizing the facility with the California Transmission system:

1. At least one week prior to synchronizing the facility with the grid for testing, provide the California ISO a letter stating the proposed date of synchronization; and

2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the ISO Outage Coordination Department.

Verification: The project owner shall provide copies of the California ISO letter to the CPM when it is sent to the California ISO one week prior to initial synchronization with the grid. The project owner shall contact the California ISO Outage Coordination Department, Monday through Friday, between the hours of 0700 and 1530 at (916) 351-2300 at least one business day prior to synchronizing the facility with the grid for testing. A report of conversation with the California ISO shall be provided electronically to the CPM one day before synchronizing the facility with the California transmission system for the first time.

TSE-8 The project owner shall be responsible for the inspection of the transmission facilities during and after project construction, and any subsequent CPM and CBO approved changes thereto, to ensure conformance with CPUC GO-95 or NESC, Title 8, CCR, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", applicable interconnection standards, NEC and related industry standards. In case of non-conformance, the project owner shall inform the CPM and CBO in writing, within 10 days of discovering such non-conformance and describe the corrective actions to be taken.

Verification: Within 60 days after first synchronization of the project, the project owner shall transmit to the CPM and CBO:

a. "As built" engineering description(s) and one-line drawings of the electrical portion of the facilities signed and sealed by the registered electrical engineer in responsible charge. A statement attesting to conformance with CPUC GO-95 or NESC, Title 8, California Code of Regulations, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", and applicable interconnection standards, NEC, related industry standards, and these conditions shall be provided concurrently.

b. An "as built" engineering description of the mechanical, structural, and civil portion of the transmission facilities signed and sealed by the registered engineer in responsible charge or acceptable alternative verification. "As built" drawings of the electrical, mechanical, structural, and civil portion of the transmission facilities shall be maintained at the power plant and made available, if requested, for CPM audit as set forth in the "Compliance Monitoring Plan".

c. A summary of inspections of the completed transmission facilities, and identification of any nonconforming work and corrective actions taken, signed and sealed by the registered engineer in charge

REFERENCES

California ISO (California Independent System Operator). 1998a. Cal-ISO Tariff Scheduling Protocol posted April 1998, Amendments 1,4,5,6, and 7 incorporated.

California ISO (California Independent System Operator). 1998b. Cal-ISO Dispatch Protocol posted April 1998.

California ISO (California Independent System Operator). 2002a. Cal-ISO Grid Planning Standards, February 2002.

CP 2009a, Hydrogen Energy International LLC, Hydrogen Energy California Project (Transitional Cluster Phase 1) submitted to the California Energy Commission.

CP 2009b, Hydrogen Energy International LLC, Hydrogen Energy California Project (Application for Certification) Submitted to the California Energy Commission.

NERC/WECC (North American Reliability Council / Western Electricity Coordinating Council), 2002. NERC/WECC Planning Standards, August 2002.

DEFINITION OF TERMS

AAC — All Aluminum conductor.

ACSR — Aluminum Conductor Steel-Reinforced.

SSAC — Steel-Supported Aluminum Conductor.

Ampacity — Current-carrying capacity, expressed in amperes, of a conductor at specified ambient conditions, at which damage to the conductor is nonexistent or deemed acceptable based on economic, safety, and reliability considerations.

Ampere — The unit of current flowing in a conductor.

Bundled — Two wires, 18 inches apart.

Bus — Conductors that serve as a common connection for two or more circuits.

Conductor — The part of the transmission line (the wire) that carries the current.

Congestion Management — Congestion management is a scheduling protocol, which provides that dispatched generation and transmission loading (imports) will not violate criteria.

Emergency Overload — See Single Contingency. This is also called an L-1.

Kcmil or KCM — Thousand circular mil. A unit of the conductor’s cross sectional area, when divided by 1,273, the area in square inches is obtained.

Kilovolt (kV) — A unit of potential difference, or voltage, between two conductors of a circuit, or between a conductor and the ground.

Loop — An electrical cul de sac. A transmission configuration that interrupts an existing circuit, diverts it to another connection and returns it back to the interrupted circuit, thus forming a loop or cul de sac.

Megavar One megavolt ampere reactive.

Megavars Mega-volt-Ampere-Reactive. One million Volt-Ampere-Reactive. Reactive power is generally associated with the reactive nature of motor loads that must be fed by generation units in the system.

Megavolt ampere (MVA)
A unit of apparent power, equals the product of the line voltage in kilovolts, current in amperes, the square root of 3, and divided by 1000.

Megawatt (MW)
A unit of power equivalent to 1,341 horsepower.

Normal Operation/ Normal Overload
When all customers receive the power they are entitled to without interruption and at steady voltage, and no element of the transmission system is loaded beyond its continuous rating.

N-1 Condition
See Single Contingency.

Outlet Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation facilities to the main grid.

Power Flow Analysis
A power flow analysis is a forward looking computer simulation of essentially all generation and transmission system facilities that identifies overloaded circuits, transformers and other equipment and system voltage levels.

Reactive Power
Reactive power is generally associated with the reactive nature of motor loads that must be fed by generation units in the system. An adequate supply of reactive power is required to maintain voltage levels in the system.

Remedial Action Scheme (RAS)
A remedial action scheme is an automatic control provision, which, for instance, will trip a selected generating unit upon a circuit overload.

SF6 Sulfur hexafluoride is an insulating medium.

Single Contingency
Also known as emergency or N-1 condition, occurs when one major transmission element (circuit, transformer, circuit breaker, etc.) or one generator is out of service.

Solid dielectric cable
Copper or aluminum conductors that are insulated by solid polyethylene type insulation and covered by a metallic shield and outer polyethylene jacket.

Switchyard A power plant switchyard (switchyard) is an integral part of a power plant and is used as an outlet for one or more electric generators.

Thermal rating See ampacity.

TSE Transmission System Engineering.

Tap A transmission configuration creating an interconnection through a sort single circuit to a small or medium sized load or a generator. The new single circuit line is inserted into an existing circuit by utilizing breakers at existing terminals of the circuit, rather than installing breakers at the interconnection in a new switchyard.

Undercrossing

	A transmission configuration where a transmission line crosses below the conductors of another transmission line, generally at 90 degrees.
Underbuild	A transmission or distribution configuration where a transmission or distribution circuit is attached to a transmission tower or pole below (under) the principle transmission line conductors.

GENERAL CONDITIONS
INCLUDING
COMPLIANCE MONITORING AND CLOSURE PLAN

Joseph Douglas

INTRODUCTION

The project's General Compliance Conditions of Certification, including Compliance Monitoring and Closure Plan (Compliance Plan) have been established as required by Public Resources Code section 25532. The plan provides a means for assuring that the facility is constructed, operated, and closed in compliance with public health and safety, environmental, and other applicable regulations, guidelines, and conditions adopted or established by the California Energy Commission and specified in the written decision on the Application for Certification or otherwise required by law.

The Compliance Plan is composed of elements that:

- set forth the duties and responsibilities of the Compliance Project Manager (CPM), the project owner, delegate agencies, and others;
- set forth the requirements for handling confidential records and maintaining the compliance record;
- state procedures for settling disputes and making post-certification changes;
- state the requirements for periodic compliance reports and other administrative procedures that are necessary to verify the compliance status for all Energy Commission approved conditions of certification;
- establish requirements for facility closure plans; and
- specify conditions of certification for each technical area containing the measures required to mitigate any and all potential adverse project impacts associated with construction, operation and closure below a level of significance. Each specific condition of certification also includes a verification provision that describes the method of assuring that the condition has been satisfied.

DEFINITIONS

The following terms and definitions are used to establish when Conditions of Certification are implemented.

PRE-CONSTRUCTION SITE MOBILIZATION

Site mobilization is limited preconstruction activities at the site to allow for the installation of fencing, construction trailers, construction trailer utilities, and construction trailer parking at the site. Limited ground disturbance, grading, and trenching associated with the above mentioned pre-construction activities is considered part of site mobilization. Walking, driving or parking a passenger vehicle, pickup truck and/or light vehicles is allowable during site mobilization.

CONSTRUCTION

Onsite work to install permanent equipment or structures for any facility.

Ground Disturbance

Construction-related ground disturbance refers to activities that result in the removal of top soil or vegetation at the site beyond site mobilization needs, and for access roads and linear facilities.

Grading, Boring, and Trenching

Construction-related grading, boring, and trenching refers to activities that result in subsurface soil work at the site and for access roads and linear facilities, e.g., alteration of the topographical features such as leveling, removal of hills or high spots, moving of soil from one area to another, and removal of soil.

Notwithstanding the definitions of ground disturbance, grading, boring, and trenching above, construction does **not** include the following:

1. the installation of environmental monitoring equipment;
2. a soil or geological investigation;
3. a topographical survey;
4. any other study or investigation to determine the environmental acceptability or feasibility of the use of the site for any particular facility; and
5. any work to provide access to the site for any of the purposes specified in “Construction” 1, 2, 3, or 4 above.

START OF COMMERCIAL OPERATION

For compliance monitoring purposes, “commercial operation” begins after the completion of start-up and commissioning, when the power plant has reached reliable steady-state production of electricity at the rated capacity. At the start of commercial operation, plant control is usually transferred from the construction manager to the plant operations manager.

COMPLIANCE PROJECT MANAGER RESPONSIBILITIES

The Compliance Project Manager (CPM) shall oversee the compliance monitoring and is responsible for:

1. ensuring that the design, construction, operation, and closure of the project facilities are in compliance with the terms and conditions of the Energy Commission Decision;
2. resolving complaints;
3. processing post-certification changes to the conditions of certification, project description (petition to amend), and ownership or operational control (petition for change of ownership) (See instructions for filing petitions);

4. documenting and tracking compliance filings; and

5. ensuring that compliance files are maintained and accessible.

The CPM is the contact person for the Energy Commission and will consult with appropriate responsible agencies, Energy Commission, and staff when handling disputes, complaints, and amendments.

All project compliance submittals are submitted to the CPM for processing. Where a submittal required by a condition of certification requires CPM approval, the approval will involve all appropriate Energy Commission staff and management. All submittals must include searchable electronic versions (pdf or MS Word files).

PRE-CONSTRUCTION AND PRE-OPERATION COMPLIANCE MEETING

The CPM usually schedules pre-construction and pre-operation compliance meetings prior to the projected start-dates of construction, plant operation, or both. The purpose of these meetings is to assemble both the Energy Commission's and project owner's technical staff to review the status of all pre-construction or pre-operation requirements contained in the Energy Commission's conditions of certification. This is to confirm that all applicable conditions of certification have been met, or if they have not been met, to ensure that the proper action is taken. In addition, these meetings ensure, to the extent possible, that Energy Commission conditions will not delay the construction and operation of the plant due to oversight and to preclude any last minute, unforeseen issues from arising. Pre-construction meetings held during the certification process must be publicly noticed unless they are confined to administrative issues and processes.

ENERGY COMMISSION RECORD

The Energy Commission shall maintain the following documents and information as a public record, in either the Compliance file or Dockets file, for the life of the project (or other period as required):

1. all documents demonstrating compliance with any legal requirements relating to the construction and operation of the facility;

2. all monthly and annual compliance reports filed by the project owner;

3. all complaints of noncompliance filed with the Energy Commission; and

4. all petitions for project or condition of certification changes and the resulting staff or Energy Commission action.

PROJECT OWNER RESPONSIBILITIES

The project owner is responsible for ensuring that the compliance conditions of certification and all other conditions of certification that appear in the Commission Decision are satisfied. The compliance conditions regarding post-certification changes specify measures that the project owner must take when requesting changes in the project design, conditions of certification, or ownership. Failure to comply with any of the conditions of certification or the compliance conditions may result in reopening of the case and revocation of Energy Commission certification; an administrative fine; or other action as appropriate. A summary of the Compliance Conditions of Certification is included as **Compliance Table 1** at the conclusion of this section.

COMPLIANCE CONDITIONS OF CERTIFICATION

Unrestricted Access (COMPLIANCE-1)

The CPM, responsible Energy Commission staff, and delegated agencies or consultants shall be guaranteed and granted unrestricted access to the power plant site, related facilities, project-related staff, and the records maintained on-site for the purpose of conducting audits, surveys, inspections, or general site visits. Although the CPM will normally schedule site visits on dates and times agreeable to the project owner, the CPM reserves the right to make unannounced visits at any time.

Compliance Record (COMPLIANCE-2)

The project owner shall maintain project files on-site or at an alternative site approved by the CPM for the life of the project, unless a lesser period of time is specified by the conditions of certification. The files shall contain copies of all “as-built” drawings, documents submitted as verification for conditions, and other project-related documents.

Energy Commission staff and delegate agencies shall, upon request to the project owner, be given unrestricted access to the files maintained pursuant to this condition.

Compliance Verification Submittals (COMPLIANCE-3)

Each condition of certification is followed by a means of verification. The verification describes the Energy Commission’s procedure(s) to ensure post-certification compliance with adopted conditions. The verification procedures, unlike the conditions, may be modified as necessary by the CPM.

Verification of compliance with the conditions of certification can be accomplished by the following:

1. monthly and/or annual compliance reports, filed by the project owner or authorized agent, reporting on work done and providing pertinent documentation, as required by the specific conditions of certification;

2. appropriate letters from delegate agencies verifying compliance;

3. energy Commission staff audits of project records; and/or

4. energy Commission staff inspections of work, or other evidence that the requirements are satisfied.

Verification lead times associated with start of construction may require the project owner to file submittals during the certification process, particularly if construction is planned to commence shortly after certification.

A cover letter from the project owner or authorized agent is required for all compliance submittals and correspondence pertaining to compliance matters. **The cover letter subject line shall identify the project by AFC number, the appropriate condition(s) of certification by condition number(s), and a brief description of the subject of the submittal**. The project owner shall also identify those submittals **not** required by a condition of certification with a statement such as: "This submittal is for information only and is not required by a specific condition of certification." When submitting supplementary or corrected information, the project owner shall reference the date of the previous submittal and CEC submittal number.

The project owner is responsible for the delivery and content of all verification submittals to the CPM, whether such condition was satisfied by work performed by the project owner or an agent of the project owner.

All hardcopy submittals shall be addressed as follows:

> **Joseph Douglas, CPM**
> **(08-AFC-8C)**
> **California Energy Commission**
> **1516 Ninth Street (MS-2000)**
> **Sacramento, CA 95814**

Those submittals shall be accompanied by a searchable electronic copy, on a CD or by e-mail, as agreed upon by the CPM.

If the project owner desires Energy Commission staff action by a specific date, that request shall be made in the submittal cover letter and shall include a detailed explanation of the effects on the project if that date is not met.

Pre-Construction Matrix and Tasks Prior to Start of Construction (COMPLIANCE-4)

Prior to commencing construction, a compliance matrix addressing only those conditions that must be fulfilled before the start of construction shall be submitted by the project owner to the CPM. This matrix will be included with the project owner's first compliance submittal or prior to the first pre-construction meeting, whichever comes first. It will be submitted in the same format as the compliance matrix described below.

Construction shall not commence until the pre-construction matrix is submitted, all pre-construction conditions have been complied with, and the CPM has issued a letter to the project owner authorizing construction. Various lead times for submittal of compliance verification documents to the CPM for conditions of certification are established to allow sufficient staff time to review and comment and, if necessary, allow the project owner to revise the submittal in a timely manner. This will ensure that project construction may proceed according to schedule.

Failure to submit compliance documents within the specified lead-time may result in delays in authorization to commence various stages of project development.

If the project owner anticipates commencing project construction as soon as the project is certified, it may be necessary for the project owner to file compliance submittals prior to project certification. Compliance submittals should be completed in advance where the necessary lead time for a required compliance event extends beyond the date anticipated for start of construction. The project owner must understand that the submittal of compliance documents prior to project certification is at the owner's own risk. Any approval by Energy Commission staff is subject to change, based upon the Commission Decision.

Compliance Reporting

There are two different compliance reports that the project owner must submit to assist the CPM in tracking activities and monitoring compliance with the terms and conditions of the Energy Commission Decision. During construction, the project owner or authorized agent will submit Monthly Compliance Reports. During operation, an Annual Compliance Report must be submitted. These reports, and the requirement for an accompanying compliance matrix, are described below. The majority of the conditions of certification require that compliance submittals be submitted to the CPM in the monthly or annual compliance reports.

Compliance Matrix (COMPLIANCE-5)

A compliance matrix shall be submitted by the project owner to the CPM along with each monthly and annual compliance report. The compliance matrix is intended to provide the CPM with the current status of all conditions of certification in a spreadsheet format. The compliance matrix must identify:

1. the technical area;
2. the condition number;
3. a brief description of the verification action or submittal required by the condition;
4. the date the submittal is required (e.g., 60 days prior to construction, after final inspection, etc.);
5. the expected or actual submittal date;
6. the date a submittal or action was approved by the Chief Building Official (CBO), CPM, or delegate agency, if applicable;
7. the compliance status of each condition, e.g., "not started," "in progress" or "completed" (include the date); and
8. if the condition was amended, the date of the amendment.

Satisfied conditions shall be placed at the end of the matrix.

Monthly Compliance Report (COMPLIANCE-6)

The first Monthly Compliance Report is due one month following the Energy Commission business meeting date upon which the project was approved, unless otherwise agreed to by the CPM. The first Monthly Compliance Report shall include the AFC number and an initial list of dates for each of the events identified on the **Key Events List. The Key Events List form is found at the end of these General Conditions.**

During pre-construction and construction of the project, the project owner or authorized agent shall submit an original and an electronic searchable version of the Monthly Compliance Report within 10 working days after the end of each reporting month. Monthly Compliance Reports shall be clearly identified for the month being reported. The reports shall contain, at a minimum:

1. a summary of the current project construction status, a revised/updated schedule if there are significant delays, and an explanation of any significant changes to the schedule;

2. documents required by specific conditions to be submitted along with the Monthly Compliance Report. Each of these items must be identified in the transmittal letter, as well as the conditions they satisfy and submitted as attachments to the Monthly Compliance Report;

3. an initial, and thereafter updated, compliance matrix showing the status of all conditions of certification;

4. a list of conditions that have been satisfied during the reporting period, and a description or reference to the actions that satisfied the condition;

5. a list of any submittal deadlines that were missed, accompanied by an explanation and an estimate of when the information will be provided;

6. a cumulative listing of any approved changes to conditions of certification;

7. a listing of any filings submitted to, or permits issued by, other governmental agencies during the month;

8. a projection of project compliance activities scheduled during the next two months. The project owner shall notify the CPM as soon as any changes are made to the project construction schedule that would affect compliance with conditions of certification;

9. a listing of the month’s additions to the on-site compliance file; and

10. a listing of complaints, notices of violation, official warnings, and citations received during the month, a description of the resolution of the resolved actions, and the status of any unresolved actions.

All sections, exhibits, or addendums shall be separated by tabbed dividers or as acceptable by the CPM.

Annual Compliance Report (COMPLIANCE-7)

After construction is complete, the project owner shall submit Annual Compliance Reports instead of Monthly Compliance Reports. The reports are for each year of commercial operation and are due to the CPM each year at a date agreed to by the CPM. Annual Compliance Reports shall be submitted over the life of the project, unless otherwise specified by the CPM. Each Annual Compliance Report shall include the AFC number, identify the reporting period, and shall contain the following:

1. an updated compliance matrix showing the status of all conditions of certification (fully satisfied conditions do not need to be included in the matrix after they have been reported as completed);

2. a summary of the current project operating status and an explanation of any significant changes to facility operations during the year;

3. documents required by specific conditions to be submitted along with the Annual Compliance Report. Each of these items must be identified in the transmittal letter with the condition it satisfies, and submitted as attachments to the Annual Compliance Report;

4. a cumulative listing of all post-certification changes approved by the Energy Commission or cleared by the CPM;

5. an explanation for any submittal deadlines that were missed, accompanied by an estimate of when the information will be provided;

6. a listing of filings submitted to, or permits issued by, other governmental agencies during the year;

7. a projection of project compliance activities scheduled during the next year;

8. a listing of the year's additions to the on-site compliance file;

9. an evaluation of the on-site contingency plan for unplanned facility closure, including any suggestions necessary for bringing the plan up to date (see Compliance Conditions for Facility Closure addressed later in this section); and

10. a listing of complaints, notices of violation, official warnings, and citations received during the year, a description of the resolution of any resolved matters, and the status of any unresolved matters.

Confidential Information (COMPLIANCE-8)

Any information that the project owner deems confidential shall be submitted to the Energy Commission's Executive Director with an application for confidentiality pursuant to Title 20, California Code of Regulations, section 2505(a). Any information that is determined to be confidential shall be kept confidential as provided for in Title 20, California Code of Regulations, section 2501, et. seq.

Annual Energy Facility Compliance Fee (COMPLIANCE-9)

Pursuant to the provisions of Section 25806(b) of the Public Resources Code, the project owner is required to pay an annual compliance fee, which is adjusted annually. Current Compliance fee information is available on the Energy Commission's website http://www.energy.ca.gov/siting/filing_fees.html. You may also contact the CPM for the current fee information. The initial payment is due on the date of the Business Meeting at which the Energy Commission adopts the final decision. All subsequent payments are due by July 1 of each year in which the facility retains its certification. The payment instrument shall be made payable to the California Energy Commission and mailed to: Accounting Office MS-02, California Energy Commission, 1516 9th St., Sacramento, CA 95814.

Reporting of Complaints, Notices, and Citations (COMPLIANCE-10)

Prior to the start of construction, the project owner must send a letter to property owners living within one mile of the project notifying them of a telephone number to contact project representatives with questions, complaints, or concerns. If the telephone is not staffed 24 hours per day, it shall include automatic answering with a date and time stamp recording. All recorded complaints shall be responded to within 24 hours. The telephone number shall be posted at the project site and made easily visible to passersby during construction and operation. The telephone number shall be provided to the CPM who will post it on the Energy Commission's web page at http://www.energy.ca.gov/sitingcases/power_plants_contacts.html.

Any changes to the telephone number shall be submitted immediately to the CPM, who will update the web page.

In addition to the monthly and annual compliance reporting requirements described above, the project owner shall report and provide copies to the CPM of all complaint forms, including noise and lighting complaints, notices of violation, notices of fines, official warnings, and citations within 10 days of receipt. Complaints shall be logged and numbered. Noise complaints shall be recorded on the form provided in the **NOISE** conditions of certification. All other complaints shall be recorded on the complaint form (Attachment A).

FACILITY CLOSURE

At some point in the future, the project will cease operation and close down. At that time, it will be necessary to ensure that the closure occurs in such a way that public health and safety and the environment are protected from adverse impacts. Although the project setting for this project does not appear, at this time, to present any special or unusual closure problems, it is impossible to foresee what the situation will be in 25 years or more when the project ceases operation. Therefore, provisions must be made that provide the flexibility to deal with the specific situation and project setting that exist at the time of closure. Laws, Ordinances, Regulations, and Standards (LORS) pertaining to facility closure are identified in the sections dealing with each technical area. Facility closure will be consistent with LORS in effect at the time of closure.

There are at least three circumstances in which a facility closure can take place: planned closure, unplanned temporary closure, and unplanned permanent closure**.**

CLOSURE DEFINITIONS

Planned Closure

A planned closure occurs when the facility is closed in an anticipated, orderly manner, at the end of its useful economic or mechanical life, or due to gradual obsolescence.

Unplanned Temporary Closure

An unplanned temporary closure occurs when the facility is closed suddenly and/or unexpectedly, on a short-term basis, due to unforeseen circumstances such as a natural disaster or an emergency.

Unplanned Permanent Closure

An unplanned permanent closure occurs if the project owner closes the facility suddenly and/or unexpectedly, on a permanent basis. This includes unplanned closure where the owner implements the on-site contingency plan. It can also include unplanned closure where the project owner fails to implement the contingency plan, and the project is essentially abandoned.

COMPLIANCE CONDITIONS FOR FACILITY CLOSURE

Planned Closure (COMPLIANCE-11)

In order to ensure that a planned facility closure does not create adverse impacts, a closure process that provides for careful consideration of available options and applicable laws, ordinances, regulations, standards, and local/regional plans in existence at the time of closure will be undertaken. To ensure adequate review of a planned project closure, the project owner shall submit a proposed facility closure plan to the Energy Commission for review and approval at least 12 months (or other period of time agreed to by the CPM) prior to the commencement of closure activities. The project owner shall file 120 copies (or other number of copies agreed upon by the CPM) of a proposed facility closure plan with the Energy Commission.

The plan shall:

1. identify and discuss any impacts and mitigation to address significant adverse impacts associated with proposed closure activities and to address facilities, equipment, or other project related remnants that will remain at the site;

2. identify a schedule of activities for closure of the power plant site, transmission line corridor, and all other appurtenant facilities constructed as part of the project;

3. identify any facilities or equipment intended to remain on site after closure, the reason, and any future use; and

4. address conformance of the plan with all applicable laws, ordinances, regulations, standards, and local/regional plans in existence at the time of facility closure, and applicable conditions of certification.

Prior to submittal of the proposed facility closure plan, a meeting shall be held between the project owner and the Energy Commission CPM for the purpose of discussing the specific contents of the plan.

In the event that there are significant issues associated with the proposed facility closure plan's approval, or if the desires of local officials or interested parties are inconsistent with the plan, the CPM shall hold one or more workshops and/or the Energy Commission may hold public hearings as part of its approval procedure.

As necessary, prior to or during the closure plan process, the project owner shall take appropriate steps to eliminate any immediate threats to public health and safety and the environment, but shall not commence any other closure activities until the Energy Commission approves the facility closure plan.

Unplanned Temporary Closure/On-Site Contingency Plan (COMPLIANCE-12)

In order to ensure that public health and safety and the environment are protected in the event of an unplanned temporary facility closure, it is essential to have an on-site contingency plan in place. The on-site contingency plan will help to ensure that all necessary steps to mitigate public health and safety impacts and environmental impacts are taken in a timely manner.

The project owner shall submit an on-site contingency plan for CPM review and approval. The plan shall be submitted no less than 60 days (or other time agreed to by the CPM) prior to commencement of commercial operation. The approved plan must be in place prior to commercial operation of the facility and shall be kept at the site at all times.

The project owner, in consultation with the CPM, will update the on-site contingency plan as necessary. The CPM may require revisions to the on-site contingency plan over the life of the project. In the annual compliance reports submitted to the Energy Commission, the project owner will review the on-site contingency plan, and recommend changes to bring the plan up to date. Any changes to the plan must be approved by the CPM.

The on-site contingency plan shall provide for taking immediate steps to secure the facility from trespassing or encroachment. In addition, for closures of more than 90 days, unless other arrangements are agreed to by the CPM, the plan shall provide for removal of hazardous materials and hazardous wastes, draining of all chemicals from storage tanks and other equipment, and the safe shutdown of all equipment. (Also see specific conditions of certification for the technical areas of **Hazardous Materials Management** and **Waste Management**)

In addition, consistent with requirements under unplanned permanent closure addressed below, the nature and extent of insurance coverage, and major equipment warranties must also be included in the on-site contingency plan. In addition, the status of the insurance coverage and major equipment warranties must be updated in the annual compliance reports.

In the event of an unplanned temporary closure, the project owner shall notify the CPM, as well as other responsible agencies, by telephone, fax, or e-mail, within 24 hours and shall take all necessary steps to implement the on-site contingency plan. The project owner shall keep the CPM informed of the circumstances and expected duration of the closure.

If the CPM determines that an unplanned temporary closure is likely to be permanent, or for a duration of more than 12 months, a closure plan consistent with the requirements for a planned closure shall be developed and submitted to the CPM within 90 days of the CPM's determination (or other period of time agreed to by the CPM).

Unplanned Permanent Closure/On-Site Contingency Plan (COMPLIANCE-13)

The on-site contingency plan required for unplanned temporary closure shall also cover unplanned permanent facility closure. All of the requirements specified for unplanned temporary closure shall also apply to unplanned permanent closure.

In addition, the on-site contingency plan shall address how the project owner will ensure that all required closure steps will be successfully undertaken in the event of abandonment.

In the event of an unplanned permanent closure, the project owner shall notify the CPM, as well as other responsible agencies, by telephone, fax, or e-mail within 24 hours and shall take all necessary steps to implement the on-site contingency plan. The project owner shall keep the CPM informed of the status of all closure activities.

A closure plan, consistent with the requirements for a planned closure, shall be developed and submitted to the CPM within 90 days of the permanent closure or another period of time agreed to by the CPM.

Post Certification Changes to the Energy Commission Decision: Amendments, Ownership Changes, Staff Approved Project Modifications and Verification Changes (COMPLIANCE-14)

The project owner must petition the Energy Commission pursuant to Title 20, California Code of Regulations, section 1769, in order to modify the project (including linear facilities) design, operation or performance requirements, and to transfer ownership or operational control of the facility. **It is the responsibility of the project owner to contact the CPM to determine if a proposed project change should be considered a project modification pursuant to section 1769.** Implementation of a project modification without first securing Energy Commission, or Energy Commission staff approval, may result in enforcement action that could result in civil penalties in accordance with section 25534 of the Public Resources Code.

A petition is required for **amendments** and for **staff approved project modifications** as specified below. Both shall be filed as a "Petition to Amend." Staff will determine if the change is significant or insignificant. For verification changes, a letter from the project owner is sufficient. In all cases, the petition or letter requesting a change should be submitted to the CPM, who will file it with the Energy Commission's Dockets Unit in accordance with Title 20, California Code of Regulations, section 1209.

The criteria that determine which type of approval and the process that applies are explained below. They reflect the provisions of Section 1769 at the time this condition was drafted. If the Commission's rules regarding amendments are amended, the rules in effect at the time an amendment is requested shall apply.

Amendment

The project owner shall petition the Energy Commission, pursuant to Title 20, California Code of Regulations, Section 1769(a), when proposing modifications to the project (including linear facilities) design, operation, or performance requirements. If a proposed modification results in deletion or change of a condition of certification, or makes changes that would cause the project not to comply with any applicable laws, ordinances, regulations, or standards the petition will be processed as a formal amendment to the final decision, which requires public notice and review of the Energy Commission staff analysis and approval by the full Commission. The petition shall be in the form of a legal brief and fulfill the requirements of Section 1769(a). Upon request, the CPM will provide a sample petition to use as a template.

Change of Ownership

Change of ownership or operational control also requires that the project owner file a petition pursuant to section 1769 (b). This process requires public notice and approval by the full Commission. The petition shall be in the form of a legal brief and fulfill the requirements of Section 1769(b). Upon request, the CPM will provide a sample petition to use as a template.

Staff Approved Project Modification

Modifications that do not result in deletions or changes to conditions of certification, that are compliant with laws, ordinances, regulations and standards and will not have significant environmental impacts may be authorized by the CPM as a staff approved project modification pursuant to section 1769(a) (2). Once staff files an intention to approve the proposed project modifications, any person may file an objection to staff's determination within 14 days of service on the grounds that the modification does not meet the criteria of section 1769 (a)(2). If a person objects to staff's determination, the petition must be processed as a formal amendment to the decision and must be approved by the full commission at a noticed business meeting or hearing.

Verification Change

A verification may be modified by the CPM without requesting an amendment to the decision if the change does not conflict with the conditions of certification and provides an effective alternate means of verification.

CBO DELEGATION AND AGENCY COOPERATION

In performing construction and operation monitoring of the project, Energy Commission staff acts as, and has the authority of, the Chief Building Official (CBO). Energy

Commission staff may delegate CBO responsibility to either an independent third party contractor or the local building official. Energy Commission staff retains CBO authority when selecting a delegate CBO, including enforcing and interpreting state and local codes, and use of discretion, as necessary, in implementing the various codes and standards.

Energy Commission staff may also seek the cooperation of state, regional, and local agencies that have an interest in environmental protection when conducting project monitoring.

ENFORCEMENT

The Energy Commission's legal authority to enforce the terms and conditions of its Decision is specified in Public Resources Code sections 25534 and 25900. The Energy Commission may amend or revoke the certification for any facility, and may impose a civil penalty for any significant failure to comply with the terms or conditions of the Energy Commission Decision. The specific action and amount of any fines the Energy Commission may impose would take into account the specific circumstances of the incident(s). This would include such factors as the previous compliance history, whether the cause of the incident involves willful disregard of LORS, oversight, unforeseeable events, and other factors the Energy Commission may consider.

NONCOMPLIANCE COMPLAINT PROCEDURES

Any person or agency may file a complaint alleging noncompliance with the conditions of certification. Such a complaint will be subject to review by the Energy Commission pursuant to Title 20, California Code of Regulations, section 1237, but in many instances the noncompliance can be resolved by using the informal dispute resolution process. Both the informal and formal complaint procedure, as described in current State law and regulations, are described below. They shall be followed unless superseded by future law or regulations.

Informal Dispute Resolution Process

The following procedure is designed to informally resolve disputes concerning the interpretation of compliance with the requirements of this compliance plan. The project owner, the Energy Commission, or any other party, including members of the public, may initiate an informal dispute resolution process. Disputes may pertain to actions or decisions made by any party, including the Energy Commission's delegate agents.

This process may precede the more formal complaint and investigation procedure specified in Title 20, California Code of Regulations, section 1237, but is not intended to be a substitute for, or prerequisite to it. This informal procedure may not be used to change the terms and conditions of certification as approved by the Energy Commission, although the agreed upon resolution may result in a project owner, or in some cases the Energy Commission staff, proposing an amendment.

The process encourages all parties involved in a dispute to discuss the matter and to reach an agreement resolving the dispute. If a dispute cannot be resolved, then the matter must be brought before the full Energy Commission for consideration via the complaint and investigation procedure.

Request for Informal Investigation

Any individual, group, or agency may request the Energy Commission to conduct an informal investigation of alleged noncompliance with the Energy Commission's terms and conditions of certification. All requests for informal investigations shall be made to the designated CPM.

Upon receipt of a request for an informal investigation, the CPM shall promptly notify the project owner of the allegation by telephone and letter. All known and relevant information of the alleged noncompliance shall be provided to the project owner and to the Energy Commission staff. The CPM will evaluate the request and the information to determine if further investigation is necessary. If the CPM finds that further investigation is necessary, the project owner will be asked to promptly investigate the matter. Within seven working days of the CPM's request, provide a written report to the CPM of the results of the investigation, including corrective measures proposed or undertaken. Depending on the urgency of the noncompliance matter, the CPM may conduct a site visit and/or request the project owner to also provide an initial verbal report, within 48 hours.

Request for Informal Meeting

In the event that either the party requesting an investigation or the Energy Commission staff is not satisfied with the project owner's report, investigation of the event, or corrective measures proposed or undertaken, either party may submit a written request to the CPM for a meeting with the project owner. Such request shall be made within 14 days of the project owner's filing of its written report. Upon receipt of such a request, the CPM shall:

1. immediately schedule a meeting with the requesting party and the project owner, to be held at a mutually convenient time and place;

2. secure the attendance of appropriate Energy Commission staff and staff of any other agencies with expertise in the subject area of concern, as necessary;

3. conduct such meeting in an informal and objective manner so as to encourage the voluntary settlement of the dispute in a fair and equitable manner;

4. After the conclusion of such a meeting, promptly prepare and distribute copies to all in attendance and to the project file, a summary memorandum that fairly and accurately identifies the positions of all parties and any understandings reached. If an agreement has not been reached, the CPM shall inform the complainant of the formal complaint process and requirements provided under Title 20, California Code of Regulations, section 1230, et. seq.

Formal Dispute Resolution Procedure-Complaints and Investigations

Any person may file a complaint with the Energy Commission's Dockets Unit alleging noncompliance with a Commission decision adopted pursuant to Public Resources

Code section 25500. Requirements for complaint filings and a description of how complaints are processed are in Title 20, California Code of Regulations, section 1237.

COMPLIANCE TABLE 1
SUMMARY of COMPLIANCE CONDITIONS OF CERTIFICATION

KEY EVENTS LIST

PROJECT: ____

DOCKET #: ____

COMPLIANCE PROJECT MANAGER: ___________________________

EVENT DESCRIPTION	DATE
Certification Date	
Obtain Site Control	
Online Date	
POWER PLANT SITE ACTIVITIES	
Start Site Mobilization	
Start Ground Disturbance	
Start Grading	
Start Construction	
Begin Pouring Major Foundation Concrete	
Begin Installation of Major Equipment	
Completion of Installation of Major Equipment	
First Combustion of Gas Turbine	
Obtain Building Occupation Permit	
Start Commercial Operation	
Complete All Construction	
TRANSMISSION LINE ACTIVITIES	
Start T/L Construction	
Synchronization with Grid and Interconnection	
Complete T/L Construction	
FUEL SUPPLY LINE ACTIVITIES	
Start Gas Pipeline Construction and Interconnection	
Complete Gas Pipeline Construction	
WATER SUPPLY LINE ACTIVITIES	
Start Water Supply Line Construction	
Complete Water Supply Line Construction	

CONDITION NUMBER	SUBJECT	DESCRIPTION
COMPLIANCE-1	Unrestricted Access	The project owner shall grant Energy Commission staff and delegate agencies or consultants unrestricted access to the power plant site.
COMPLIANCE-2	Compliance Record	The project owner shall maintain project files on-site. Energy Commission staff and delegate agencies shall be given unrestricted access to the files.
COMPLIANCE-3	Compliance Verification Submittals	The project owner is responsible for the delivery and content of all verification submittals to the CPM, whether such condition was satisfied by work performed or the project owner or his agent.
COMPLIANCE-4	Pre-construction Matrix and Tasks Prior to Start of Construction	Construction shall not commence until the all of the following activities/submittals have been completed: • property owners living within one mile of the project have been notified of a telephone number to contact for questions, complaints or concerns, • a pre-construction matrix has been submitted identifying only those conditions that must be fulfilled before the start of construction, • all pre-construction conditions have been complied with, • the CPM has issued a letter to the project owner authorizing construction.
COMPLIANCE-5	Compliance Matrix	The project owner shall submit a compliance matrix (in a spreadsheet format) with each monthly and annual compliance report which includes the status of all compliance conditions of certification.
COMPLIANCE-6	Monthly Compliance Report including a Key Events List	During construction, the project owner shall submit Monthly Compliance Reports (MCRs) which include specific information. The first MCR is due the month following the Energy Commission business meeting date on which the project was approved and shall include an initial list of dates for each of the events identified on the Key Events List.
COMPLIANCE-7	Annual Compliance Reports	After construction ends and throughout the life of the project, the project owner shall submit Annual Compliance Reports instead of Monthly Compliance Reports.

COMPLIANCE TABLE 1
SUMMARY of COMPLIANCE CONDITIONS OF CERTIFICATION

COMPLIANCE-8	Confidential Information	Any information the project owner deems confidential shall be submitted to the Energy Commission's Executive Director with a request for confidentiality.
COMPLIANCE-9	Annual fees	Payment of Annual Energy Facility Compliance Fee
COMPLIANCE-10	Reporting of Complaints, Notices and Citations	Within 10 days of receipt, the project owner shall report to the CPM, all notices, complaints, and citations.
COMPLIANCE-11	Planned Facility Closure	The project owner shall submit a closure plan to the CPM at least 12 months prior to commencement of a planned closure.
COMPLIANCE-12	Unplanned Temporary Facility Closure	To ensure that public health and safety and the environment are protected in the event of an unplanned temporary closure, the project owner shall submit an on-site contingency plan no less than 60 days prior to commencement of commercial operation.
COMPLIANCE-13	Unplanned Permanent Facility Closure	To ensure that public health and safety and the environment are protected in the event of an unplanned permanent closure, the project owner shall submit an on-site contingency plan no less than 60 days prior to commencement of commercial operation.
COMPLIANCE-14	Post-certification changes to the Decision	The project owner must petition the Energy Commission to delete or change a condition of certification, modify the project design or operational requirements and/or transfer ownership of operational control of the facility.

COMPLAINT LOG NUMBER:_______________________ DOCKET NUMBER:________________________

PROJECT NAME:____

COMPLAINT INFORMATION

NAME:____ PHONE NUMBER:___________________________

ADDRESS:____

COMPLAINT

DATE COMPLAINT RECEIVED:________________________ TIME COMPLAINT RECEIVED:_________________

COMPLAINT RECEIVED BY: ☐ TELEPHONE ☐ IN WRITING (COPY ATTACHED)

DATE OF FIRST OCCURRENCE:____

DESCRIPTION OF COMPLAINT (INCLUDING DATES, FREQUENCY, AND DURATION):________________________

____

____

FINDINGS OF INVESTIGATION BY PLANT PERSONNEL:____

____

____

DOES COMPLAINT RELATE TO VIOLATION OF A CEC REQUIREMENT? ☐ YES ☐ NO

DATE COMPLAINTANT CONTACTED TO DISCUSS FINDINGS:____________________________________

DESCRIPTION OF CORRECTIVE MEASURES TAKEN OR OTHER COMPLAINT RESOLUTION:__________________

____

____

DOES COMPLAINT AGREE WITH PROPOSED RESOLUTION? ☐ YES ☐ NO

IF NOT, EXPLAIN:____

____

CORRECTIVE ACTION

IF CORRECTIVE ACTION NECESSARY, DATE COMPLETED:____

DATE FIRST LETTER SENT TO COMPLAINT (COPY ATTACHED):___________________________________

DATE FINAL LETTER SENT TO COMPLAINT (COPY ATTACHED):___________________________________

OTHER RELEVANT INFORMATION:____

____

____

"This information is certified to be correct."

PLANT MANAGER SIGNATURE:________________________________ DATE:_______________________

(ATTACH ADDITIONAL PAGES AND ALL SUPPORTING DOCUMENTATION, AS REQUIRED)

PREPARATION TEAM

HYDROGEN ENERGY CALIFORNIA (08-AFC-8)
PREPARATION TEAM
(Part 1)

Executive Summary ……………………………………………………………….. Rod Jones

Introduction …………………………………………………………………… Rod Jones

Project Description ………………………………………………………… Rod Jones

Air Quality ………………………………………………………………….. William Walters

Hazardous Materials Management …………… Alvin J. Greenberg, Ph.D. and Rick Tyler

Noise and Vibration.. Erin Bright

Public Health ....Alvin J. Greenberg, Ph.D.

Socioeconomic Resources.. Scott DeBauche

Traffic and Transportation... Scott Debauche

Transmission Line Safety and Nuisance................................. Obed Odoemelam, Ph.D.

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Facility Design... Erin Bright

Geology and Paleontology.. Dal Hunter, Ph.D., C.E.G.

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Power Plant Reliability.. Shahab Khoshmashrab

Transmission System Engineering.. Sudath Arachchige

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

APPLICATION FOR CERTIFICATION
FOR THE *HYDROGEN ENERGY CALIFORNIA PROJECT*

Docket No. 08-AFC-8

PROOF OF SERVICE LIST
Rev. 8/18/10

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DECLARATION OF SERVICE

I, Teraja` Golston, declare that on _ August 31, 2010, I served and filed copies of the attached (08-AFC-8) Hydrogen Energy Project – Preliminary Staff Assessment – Part 1. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: [http://www.energy.ca.gov/sitingcases/hydrogen_energy].

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

(*Check all that Apply*)

FOR SERVICE TO ALL OTHER PARTIES:

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

_____ by personal delivery;

_X_ by delivering on this date, for mailing with the United States Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses NOT marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

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

OR

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

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 08-AFC-8
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

________ Original Signature in Dockets ______
Teraja` Golston