Preliminary Staff Assessment

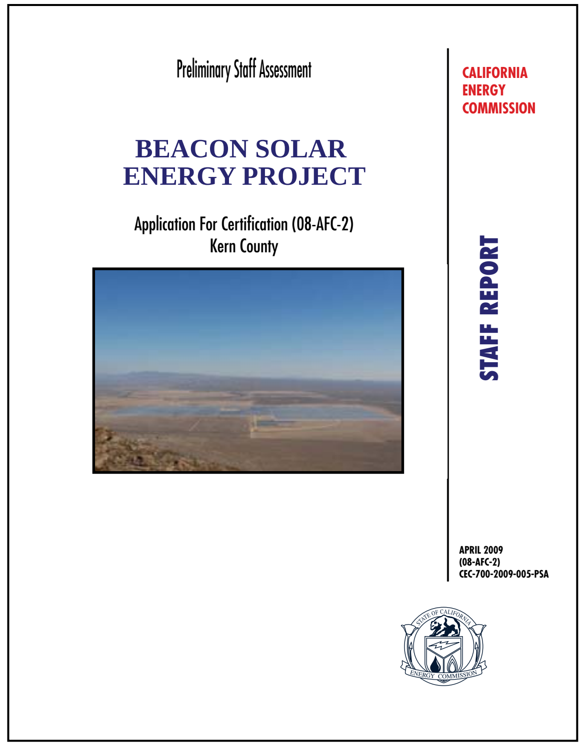
BEACON SOLAR ENERGY PROJECT

Application For Certification (08-AFC-2)
Kern County

CALIFORNIA ENERGY COMMISSION

STAFF REPORT

APRIL 2009
(08-AFC-2)
CEC-700-2009-005-PSA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CALIFORNIA ENERGY COMMISSION

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BEACON SOLAR ENERGY PROJECT
(08-AFC-2)
PRELIMINARY STAFF ASSESSMENT

EXECUTIVE SUMMARY

Eric K. Solorio

INTRODUCTION

This Preliminary Staff Assessment (PSA) contains the California Energy Commission staff's independent evaluation of the Beacon Solar Energy Project (BSEP) Application for Certification (08-AFC-2). The PSA examines engineering, environmental, public health and safety aspects of the BSEP project, based on the information provided by the applicant 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 identify the potential impacts on the environment, the public's health and safety, and determine whether the project conforms to all applicable laws, ordinances, regulations and standards (LORS). Upon identifying any potentially significant environmental impacts, staff recommends mitigation measures in the form of conditions of certification for construction, operation and eventual closure of the project.

This PSA is not the decision document for these proceedings nor does it contain final findings of the Energy Commission related to environmental impacts or the project's compliance with local/state/federal legal requirements. Following a 30-day public comment period on the PSA, the PSA will be superseded by staff's Final Staff Assessment (FSA) which will serve as staff's formal testimony in evidentiary hearings to be held by the Energy Commission Committee assigned to hear this case. The Committee will hold evidentiary hearings and will consider the recommendations presented by staff, applicant, interveners, government agencies, and the public prior to proposing its decision. In the last step, the full Energy Commission will issue the final decision.

ENERGY COMMISSION'S "IN LIEU" PERMITTING PROCESS

Staff has implemented an objective of the Renewable Energy Action Team (REAT), as identified in the Governor's Executive Order S-14-08, to create a "one stop" process for permitting renewable energy generation facilities under California law. This permit streamlining process is being implemented according to the Energy Commission's "in lieu permit" authority established under the Warren-Alquist Act. Accordingly, staff has coordinated joint environmental review with other agencies such as the U.S. Fish and Wildlife Service, California Department of Fish and Game, California State Water Resources Control Board, and Kern County to facilitate the Energy Commission issuing all of the necessary state and local permits within the Commission's certification process. By implementing this cooperative approach, staff is able to reduce the overall state permit processing time for the BSEP. For example the local water board, Lohantan Regional Water

Quality Control Board, normally requires a certified CEQA document before its Board will approve a Waste Discharge Report (permit). Typically, Lahontan's Board hearings would take place a minimum of four months after a final decision by the Energy Commission. Other examples include staff incorporating the Incidental Take Permit and a Streambed Alteration Agreement that would otherwise be processed by the California Department of Fish and Game after the environmental review was completed. If certified by the Commission, the Beacon Solar Energy Project will benefit by having each of these permits and agreements subsumed into the Energy Commission's certification process thus saving the applicant the additional processing time otherwise required to engage each agency separately after being certified by the Commission.

PROJECT LOCATION AND DESCRIPTION

The proposed 2,012-acre project site is located in eastern Kern County at the western edge of the Mojave Desert, just east of the southern end of the Sierra Nevada mountain range. The site is located approximately 4 miles northwest of California City's northern boundary, approximately 15 miles north of the town of Mojave, and approximately 24 miles northeast of the City of Tehachapi. Koehn Lake is located approximately five miles to the east-northeast, and Red Rock Canyon State Park is located approximately four miles to the north.

The site is vacant and previously disturbed from past agricultural activities, which ceased in the early 1980s. The site is relatively flat with elevations ranging from approximately 2,220 feet above mean sea level in the southwest to 2,025 feet in the northeast. Pine Tree Creek is a dry desert wash that trends south-southwest to north-northeast through the center of the site. The applicant proposes to reroute the wash to the southern and eastern boundaries of the project site. There is also a fault zone crossing the site from southwest to northwest resulting in up to a 10-foot step change in elevation across the fault zone. The fault zone is described in more detail in the **GEOLOGY AND PALEONTOLOGY** section of this Preliminary Staff Assessment (PSA).

The applicant's basic process for solar electric power generation would be to utilize parabolic trough solar collectors to concentrate solar energy onto heat collection elements (HCE) that contain a fluid, referred to as *heat transfer fluid* (HTF). After being heated in the solar troughs, the HTF is run through a heat exchanger where it heats water into steam. In the next stage, the steam is converted into electricity utilizing a Rankine-cycle reheat steam turbine electric generator, which is housed in the power block facility. After the steam is cycled through the turbine, it is processed through a cooling tower where it is condensed back to a liquid form (water) and recycled through the system again to drive the steam turbine generator.

The project site arrangement generally consists of a 1,266-acre, rectangular arrangement of parabolic trough solar collectors surrounding a centrally located power block. The power block facility houses the majority of electrical generation equipment and related systems, with exception of the solar field. The solar collectors would be constructed in long rows (troughs) across the project site and aligned side by side in a north-south orientation to allow the troughs to slowly rotate from east to west, tracking the movement of the sun. Adjoining the solar field, immediately to the west, are various support facilities, including administration and storage buildings, and evaporation ponds.

PUBLIC AND AGENCY COORDINATION

On March 27, 2008, the Energy Commission staff issued a notification of receipt of the Application for Certification (AFC), together with a project description, to property owners within 1,000 feet of the proposed project and those located within 500 feet of the linear facilities. Staff sent a similar notification and a copy of the AFC to a comprehensive list of agencies and libraries. Staff's notification letters requested public and agency review and comment on the AFC, and invited continued participation in the Energy Commission's certification process.

The Energy Commission's Public Adviser's Office (PAO) reviewed information available from the applicant and others and then conducted its own, extensive outreach efforts to identify certain local officials, as well as interested entities within a six-mile radius around the proposed site for the Beacon Solar Energy Project. These entities include schools, churches, community, cultural and health-care facilities, and day-care and senior-care centers, as well as business, environmental, governmental, and ethnic organizations. By means of mailing letters and bilingual (English and Spanish) notices, the PAO notified these entities of the Committee's Informational Hearing and Site Visit for the project, held on June 11, 2008, in California City. The PAO also identified and similarly notified 13 local officials with jurisdiction in the project area. These officials included the board of supervisors and the executive officer for Kern County, as well as the city council and manager for California City.

The PAO also arranged for advertisements in English and Spanish in the June 5, 2008 issue of the *Mojave Desert News* and requested public service announcements in English and Spanish at television and radio stations broadcasting in the project area.

In addition to the outreach efforts of the PAO, staff has continued to solicit comments on the AFC from local, state and federal agencies that have an interest in the project including Kern County Planning Department and Public Works Department, Kern County Air Pollution Control District, Cal-Trans, Lahontan Regional Water Quality Control Board, U.S. Fish and Wildlife Service, and California Department of Fish and Game. Staff has also considered the comments of interveners, community groups, and individual members of the public.

PUBLIC WORKSHOPS

On July 22, 2008, staff conducted a publicly noticed Data Response and Issue Resolution workshop at the California City Council Chambers and discussed the topics of Air Quality, Biology, Cultural Resources, Socioeconomics, Soils, Transmission System Engineering, Waste Management, and Water Resources. The purpose of the workshop was to provide members of the community and governmental agencies opportunity to obtain project information, and to offer comments they may have had regarding any aspect of the proposed project.

On August 25, 2008, staff conducted a second publicly noticed Data Response and Issue Resolution workshop at the office of the U.S. Fish and Wildlife Service in Ventura, California and discussed potential project-related impacts to desert tortoise, Mohave ground squirrel, and other species of special concern.

On November 6 2008, staff conducted a third publicly noticed Data Response and Issue Resolution workshop at the California City Council Chambers and discussed the proposed evaporation ponds, the proposed rerouting of Pine Tree Creek, mitigation plans and compensation ratios for special status species and associated habitat, water usage, potential impacts to groundwater, and evaluation of locations within the site and transmission line boundaries that may be eligible for listing on the California Register of Historic Resources.

LIBRARIES

On March 27, 2008, the Energy Commission staff sent the BSEP Application for Certification to various libraries located in Kern County (California City Branch, Mojave Branch, Wanda Kirk Branch, Ridgecrest Branch, and Tehachapi Branco) and to libraries in Eureka, Fresno, Los Angeles, Sacramento, San Diego, and San Francisco.

ENVIRONMENTAL JUSTICE

The steps recommended by the U.S. EPA'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 staff's environmental justice analysis. Staff has followed each of the above steps for the following 11 sections in the PSA: Air Quality, Hazardous Materials, Land Use, Noise, Public Health, Socioeconomics, Soils and Water, Traffic and Transportation, Transmission Line Safety/Nuisance, Visual Resources, and Waste Management. Over the course of the analysis for each of the 11 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:

- the minority population of the affected area is greater than fifty percent 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.

As a result of staff's analysis, staff determined there are not any environmental justice issues for the proposed Beacon Solar Energy Project. Staff identified the following economic benefits from the project: capital costs; construction and operation payroll; property and sales taxes; and school impact fees.

STAFF'S ASSESSMENT OF PROJECT RELATED IMPACTS

With the exception of two resource areas, Soil and Water Resources and Visual Resources, staff believes that with the Commission's adoption of staff's proposed mitigation measures and the proposed conditions of certification, the BSEP project would not cause significant adverse impacts and would comply with all applicable laws, ordinances, regulations, and standards (LORS). For a more detailed review of potential environmental impacts, see staff's technical analyses in the PSA. The status of each technical area is summarized in the table below and the subsequent text.

Executive Summary Table 1
Summary of Impacts to Each Technical Area

Technical Area	Complies with LORS	Impacts Mitigated
Air Quality	Yes	Yes
Biological Resources	Yes	Yes
Cultural Resources	Yes	Yes
Efficiency	Not Applicable	Not Applicable
Facility Design	Yes	Yes
Geology & Paleontology	Yes	Yes
Hazardous Materials	Yes	Yes
Land Use	Yes	Yes
Noise and Vibration	Yes	Yes
Public Health	Yes	Yes
Reliability	Not Applicable	Not Applicable
Socioeconomic Resources	Yes	Yes
Soil & Water Resources	***No***	***No***
Traffic & Transportation	Yes	Yes
Transmission Line Safety/Nuisance	Yes	Yes
Transmission System Engineering	Yes	Yes
Visual Resources	***No***	***No***
Waste Management	Yes	Yes
Worker Safety and Fire Protection	Yes	Yes

SOIL AND WATER RESOURCES

Staff has determined that as proposed, the BSEP could create potentially significant impacts to Soil and Water Resources, which the applicant has not proposed to mitigate.

Staff has determined that without incorporating one of the project alternatives identified in the **ALTERNATIVES** section or a similar alternative that yields the same results, the BSEP project, as proposed, would not comply with certain applicable LORS nor comply with state policies regarding the use of fresh water in industrial applications and power plant cooling systems. Staff summarizes its conclusions as follows:

- BSEP's proposed use of potable groundwater for power plant cooling and the project's process and potable water needs would cause a significant adverse impact to potable water resources and could affect current and future users of groundwater.
- BSEP has not demonstrated that utilizing alternative water supply sources or alternative cooling technologies and using a "zero-liquid discharge" system are “environmentally undesirable” or "economically unsound", as required by Energy Commission policyas enumerated in the 2003 Integrated Energy Policy Report.
- BSEP proposes to fill Pine Tree Creek and construct a two-mile long, diversion channel in a manner that staff has concluded would impact adjacent properties with flood flows. Staff and California Department of Fish and Game have determined the proposed design of the rerouted wash is currently deficient. Applicant is reevaluating the design and will provide a revised design prior to the FSA being finalized.

VISUAL RESOURCES

The introduction of the BSEP would change the existing physical setting of the Fremont Valley floor from a moderately disturbed desert floor landscape to a highly human-altered landscape. This change principally would be due to 1,244 acres of the project site being covered with parabolic trough solar collectors. In addition, the introduction of the radiance from the parabolic trough arrays during operation would be prominent from elevated locations. Staff concludes the project would introduce a substantial significant “Aesthetic” impact under the California Environmental Quality Act and Guidelines at two selected key observation points (KOPs) that would be unmitigable.

ALTERNATIVES SUMMARY

Staff concluded the “no project’ alternative is not a reasonable alternative to the proposed project, but there are seven feasible project alternatives that are reasonable alternatives to the proposed BSEP. Each of the seven alternatives is a reasonable alternative to the proposed BSEP because each alternative could reduce the BSEP’s consumption of potable water by up to 97 percent. Five of the alternatives involve using a non-potable water source (brackish water) for wet cooling and power production. The sixth alternative would utilize the proven technology of dry cooling which does not require the use of water in the cooling process. The seventh alternative is utilizing photovoltaic technology (PV) which does not require a cooling system or the related water use.

Both PV and dry cooling have the added benefit of not only eliminating 97 percent of the water use but also eliminating the need for more than 40 acres of evaporation ponds; these ponds are a source of concern to the United States Fish and Wildlife Service and the California Department of Fish and Game. Utilizing either PV technology or dry cooling could also avoid the impacts to buried cultural resources by avoiding the mass grading activities required to excavate more than 40 acres of evaporation ponds. Although staff has determined that incorporating any of the seven project alternatives would avoid or greatly reduce some of the anticipated environmental impacts of the proposed project, staff has concluded that PV technology or dry cooling could avoid and reduce significant environmental impacts more than the five other project alternatives. Staff's conclusion is that all seven alternatives are reasonable alternatives to the proposed BSEP and economically feasible to incorporate, as described in detail in the **ALTERNATIVES** section, **ALTERNATIVES APPENDIX A**, and the **SOIL AND WATER RESOURCES** section.

NOTEWORTHY PUBLIC BENEFITS

BSEP offers the benefit of providing nearly 100 percent of its power generation from the sun. The daylight operating hours generally coincide with the normal hours when peaking capacity and energy is needed to support the California ISO transmission grid. In addition, staff has identified the following significant and environmentally important public benefits:

1. BSEP would contribute to meeting goals under California's Renewable Portfolio Standard Program (Senate Bill 1078), which establishes that 20 percent of the total electricity sold to retail customers in California per year by December 31, 2010 must consist of renewable energy;

2. BSEP would contribute to meeting the Governor's Executive Order #S-14-08 which establishes that renewable energy must contribute 33 percent of the supply for meeting total state energy demands by 2020;

3. BSEP would contribute to the state accomplishing its goals for reducing global carbon emissions in accordance with the California Global Warming Solutions Act of 2006 (Assembly Bill 32);

Staff has identified additional noteworthy public benefits which would include both short term construction-related and long term operational-related increases in local expenditures and payrolls, as well as sales tax revenues. Please see the Socioeconomics section of the PSA for a more detailed discussion of these project benefits.

RECOMMENDATIONS AND SCHEDULE

For a more detailed review of potential impacts and staff's recommended mitigation measures, please refer to staff's 19 separate technical analyses sections of the PSA. Staff has identified any outstanding issues in the respective technical sections of the PSA. To resolve these issues, staff requires either additional data, further discussion and analysis, or is awaiting conditions from a permitting agency prescribing mitigation or participating in a joint environmental review with staff.

In conclusion, staff will work to resolve the outstanding issues and update our preliminary conclusions for the FSA. Staff believes that solar energy projects are an important component to addressing the significant environmental threats associated with global warming. As such, we are committed to working constructively with the applicant and all other parties in this proceeding to facilitate timely review and to improve the project where feasible. Consistent with the Governor's Executive Order #S-14-08, staff will continue to coordinate a joint environmental review with other agencies such as the U.S. Fish and Wildlife Service, California Department of Fish and Game, California State Water Resources Control Board and Kern County to facilitate the Energy Commission issuing all of the necessary state and local permits within the Commission's certification process.

Staff plans to conduct the first public workshop on the PSA on April 14, 2009. In the event applicant and staff are able to resolve all outstanding issues at the public workshop, then staff anticipates publication of the Final Staff Assessment (FSA) on May 18, 2009, assuming that applicant responds in a timely fashion in providing any outstanding data previously requested by staff and/or cooperating agencies.

INTRODUCTION

Eric K. Solorio

PURPOSE OF THIS REPORT

This Preliminary Staff Assessment (PSA) is the California Energy Commission staff's independent analysis of the proposed Beacon Solar Energy Project (hereafter referred to as BSEP). For clarity, this PSA is a staff document. It is neither a California Energy Commission Committee document nor a draft decision. The PSA describes the following:

- the proposed project;
- the existing environment;
- 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;
- the potential cumulative impacts of the project in conjunction with other existing and known planned developments;
- mitigation measures proposed by the applicant, staff, interested agencies, local organizations, and interveners which 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 the: 1) Application for Certification (AFC), 2) responses to data requests, 3) supplementary information from local, state, and federal agencies, interested organizations, and individuals, 4) existing documents and publications, 5) independent research, and 6) comments at workshops. 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 that the condition of certification has been met. The PSA presents preliminary conclusions about potential environmental impacts and conformity with LORS, as well as proposed conditions that apply to the design, construction, operation, and closure of the facility.

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

ORGANIZATION OF THE PRELIMINARY STAFF ASSESSMENT

The PSA contains an Executive Summary, Introduction, Project Description, and Project Alternatives. The environmental, engineering, and public health and safety analysis of the proposed project is contained in a discussion of 20 technical areas. Each technical area is addressed in a separate chapter. These chapters are followed by a discussion of facility closure, project construction and operation compliance monitoring plans, and a list of staff that assisted in preparing this report.

Each of the 20 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;
- closure requirements;
- conclusions and recommendations; and
- conditions of certification for both construction and operation (if applicable).

ENERGY COMMISSION SITING PROCESS

The Energy Commission has the exclusive authority to certify the construction, modification, 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 thermal power plant applications for certification (AFC) to assess potential environmental impacts including potential impacts to public health and safety, potential measures to mitigate those impacts, and compliance with applicable governmental laws or standards (Pub. Resources Code, § 25519 and § 25523(d)).

The Energy Commission’s siting regulations require staff to independently review the AFC and assess whether all of the potential environmental impacts have been properly identified, and whether additional mitigation or other more effective mitigation measures are necessary, feasible, and available (Cal. Code Regs., tit. 20, § 1742 and § 1742.5(a)).

In addition, staff must assess the completeness and adequacy of the measures proposed by the applicant to ensure compliance with health and safety standards, and the reliability of power plant operations (Cal. Code Regs., tit. 20, § 1743(b)). Staff is required to develop a compliance plan (coordinated 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 CEQA. No additional environmental impact report (EIR) is required because the Energy Commission's site certification program has been certified by the California Resources Agency as meeting all requirements of a certified regulatory program (Pub. Resources Code, § 21080.5 and Cal. Code Regs., tit. 14, § 15251 (j)). The Energy Commission is the CEQA lead agency.

The staff prepares a PSA that presents for the applicant, intervenors, 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 the publishing of the PSA, staff will conduct one or more workshops to discuss its findings, 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 will then publish a Final Staff Assessment (FSA).

The FSA is only one piece of evidence that will be considered by the Committee (two Energy Commission 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 Member's Proposed Decision (PMPD). Following publication, the PMPD is circulated in order to receive written public comments. At the conclusion of the comment period, the Committee may prepare a revised PMPD. At the close of the comment period for the revised PMPD, the PMPD is submitted to the full Energy Commission for a decision.

AGENCY COORDINATION

As noted above, 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 may include as applicable the U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, U.S. Army

Corps of Engineers, California Coastal Commission, State Water Resources Control Board/Regional Water Quality Control Board, California Department of Fish and Game, and the California Air Resources Board.

OUTREACH

The Energy Commission's outreach program is primarily facilitated by the Public Adviser's Office (PAO). This is an ongoing process that to date has involved the following efforts:

LIBRARIES

On March 27, 2008, the Energy Commission staff sent the BSEP Application for Certification to various libraries located in Kern County (California City Branch, Mojave Branch, Wanda Kirk Branch, Ridgecrest Branch, and Tehachapi Branco) and to libraries in Eureka, Fresno, Los Angeles, Sacramento, San Diego, and San Francisco.

INITIAL OUTREACH EFFORTS

The PAO reviewed related information available from the applicant and others and then conducted its own, extensive outreach efforts to identify certain local officials, as well as interested entities within a six-mile radius around the proposed site for the Beacon Solar Energy Project. These entities include schools; churches; community, cultural and health-care facilities; and day-care and senior-care centers, as well as business, environmental, governmental, and ethnic organizations. By means of mailing letters and bilingual (English and Spanish) notices, the PAO notified these entities of the Informational Hearing and Site Visit for the project, held on June 11, 2008, in California City. The PAO also identified and similarly notified 13 local officials with jurisdiction in the project area. These officials included the board of supervisors and the executive officer for Kern County, as well as the city council and manager for California City.

In addition, the PAO arranged for advertisements in English and Spanish in the June 5, 2008 issue of the *Mojave Desert News* and requested public service announcements in English and Spanish at television and radio stations broadcasting in the project area.

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). This was done for the BSEP project. 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.

ENVIRONMENTAL JUSTICE

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," focuses federal attention on the environment and human health conditions of minority communities and calls on federal agencies to achieve environmental justice as part of this mission. The order requires the U.S. Environmental Protection Agency (U.S. EPA) and all other federal agencies (as well as state agencies receiving federal funds) to develop strategies to address this issue. The agencies are required to identify and address any disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and/or low-income populations.

For all siting cases, Energy Commission staff conducts an environmental justice screening analysis in accordance with the *Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA (National Environmental Policy Act) Compliance Analysis,* dated April 1998. The purpose of the screening analysis is to determine whether a minority or low-income population exists within the potentially affected area of the proposed site.

California Statute section 65040.12(c) of the Government Code defines *environmental justice* to mean "fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies." Staff's specific activities, with respect to environmental justice for the BSEP project, are discussed in the **Executive Summary**.

PROJECT DESCRIPTION

Eric K. Solorio

INTRODUCTION

Beacon Solar, LLC, a Delaware limited liability company and wholly owned subsidiary of FPL Energy, LLC (applicant), filed an Application for Certification (AFC) with the California Energy Commission (Energy Commission) on March 14, 2008, to construct and operate a nominal 250 megawatt (MW) solar thermal power plant. Staff's initial data adequacy review of the Beacon Solar Energy Project (BSEP) AFC determined that it did not meet all the requirements for the 12-month process as established by section 1704, including appendix B of chapter 5, title 20, of the California Code of Regulations. Specifically, the AFC was deficient in six of 23 areas: air quality, biological resources, cultural resources, geologic hazards, land use, and socioeconomics. On April 21, 2008, the applicant provided additional information to supplement the AFC. After reviewing the supplemental information, on April 25, 2008, staff issued a memorandum to the Energy Commission which supported the executive director's data adequacy recommendation. At a business meeting held on May 7, 2008, the Energy Commission adopted the executive director's data adequacy recommendation, thereby deeming the AFC complete for filing purposes.

PROJECT PURPOSE AND OBJECTIVES

The project purpose is to benefit FPL Energy stockholders by earning a profit on investment while achieving the stated project objectives (BS 2008a and BS 2008i). As described in the AFC, the applicant's specific project objectives are as follows:

1. to construct, operate, and maintain an efficient, economic, reliable, safe, and environmentally sound solar-powered generating facility that will help achieve: (i) the state of California objectives mandated by SB 1078 (California Renewable Portfolio Standard Program), (ii) AB 32 (California Global Warming Solutions Act of 2006), and (iii) other local mandates adopted by the state's municipal electric utilities to meet the requirements for the long-term, wholesale purchase of renewable electric energy for distribution to its customers;

2. to develop a site with available water resources to allow wet cooling in order to optimize power generation efficiency and reduce project cost;

3. to develop a site with an excellent solar resource;

4. to develop a previously disturbed site with close proximity to transmission infrastructure in order to minimize environmental impacts;

5. to interconnect directly to the Los Angeles Department of Water and Power (LADWP) electrical transmission system; and

6. to develop a new utility-scale solar energy project using proven concentrated solar trough technology.

Based upon the applicant's design objectives, staff concluded the project's objectives also include operating for up to 40 years. It is worth noting that considering the applicant's stated objective of using on-site water for wet-cooling and overall processes and the fact that the AFC identifies the on-site water as being potable water, staff therefore infers that the applicant's objectives include the use potable water for wet cooling and overall power generation processes.

PROJECT LOCATION AND SITE DESCRIPTION

The proposed 2,012-acre project site is located in eastern Kern County at the western edge of the Mojave Desert, just east of the southern end of the Sierra Nevada mountain range. The site is located approximately 4 miles northwest of California City's northern boundary, approximately 15 miles north of the town of Mojave, and approximately 24 miles northeast of the City of Tehachapi (see **Project Description Figure 1**). Koehn Lake is located approximately five miles to the east-northeast, and Red Rock Canyon State Park is located approximately four miles to the north.

The site of approximately 2,012 acres is vacant and previously disturbed from past agricultural activities, which ceased in the early 1980s. Photographs of the site are shown in **Project Description Figure 3**. The site is relatively flat, with elevations ranging from approximately 2,220 feet above mean sea level in the southwest to 2,025 feet in the northeast. Pine Tree Creek, a dry desert wash, trends south-southwest to north-northeast through the center of the site. There is also a fault zone crossing the site from southwest to northwest resulting in up to a 10-foot step change in elevation across the fault zone. The fault zone is described in more detail in the **Geology and Paleontology** section of this Preliminary Staff Assessment (PSA).

PROJECT FEATURES

SOLAR FIELD, POWER GENERATION EQUIPMENT, AND PROCESS

This section describes the proposed project site arrangement, processes, systems, and equipment. The project site arrangement generally consists of a 1,266-acre, rectangular arrangement of parabolic trough solar collectors surrounding a centrally located power block. The power block facility houses the majority of electrical generation equipment and related systems, with exception of the solar field. The solar collectors would be constructed in long rows (troughs) across the project site and aligned side by side in a north-south orientation to allow the troughs to slowly rotate from east to west, tracking the movement of the sun. Adjoining the solar field, immediately to the west, are various support facilities, including administration and storage buildings, and evaporation ponds. The site also includes Pine Tree Creek, which currently bisects the site. Pine Tree Creek is a dry desert wash that the applicant proposes to reroute to the southern and eastern boundaries of the project site. Together, the solar field, support facilities, transmission lines, and the drainage feature consume the majority of the 2,012-acre proposed project site. Please refer to **Project Description Figure 4** to see an illustration of the proposed site arrangement and refer to **Project Description Figure 7** to see a photo of typical solar collector troughs.

The applicant's basic process for solar electric power generation would be to utilize parabolic trough solar collectors to concentrate solar energy onto heat collection elements (HCE) that contain a fluid, referred to as *heat transfer fluid* (HTF). After being heated in the solar troughs, the HTF is run through a heat exchanger where it heats water into steam. In the next stage, the steam is converted into electricity utilizing a Rankine-cycle reheat steam turbine electric generator, which is housed in the power block facility. After the steam is cycled through the turbine, it is processed through a cooling tower where it is condensed back to a liquid form (water) and recycled through the system again to drive the steam turbine generator. The solar heat used in the boiler (steam) process would be supplemented by two natural gas-fired auxiliary boilers that would provide steam to supplement plant start-up and also preheat HTF whenever its temperature drops below 76 degrees Fahrenheit (°F), (08-AFC 2-9). The total supplemental heat derived from the natural gas-fired auxiliary boilers is not expected to surpass 1 percent of power generation.

The power block facility would include the main electrical building, two natural gas-fired auxiliary boilers, an air emission control system for the combustion of natural gas in the auxiliary boilers, a steam turbine generator, a cooling tower, water treatment equipment, a hazardous materials storage area, auxiliary equipment (emergency diesel generator, diesel fire pump, etc.), a raw water storage tank (2.9 million gallons), a treated water storage tank (2.4 million gallons), a de-mineralized water storage tank (150,000 gallons), and a neutralization water storage tank (80,000 gallons). Other support facilities include:

- a land farm for remediation of contaminated soils;
- an administration building and warehouse;
- three 8.3-acre, evaporation ponds (25 acres total);
- on-site access and maintenance roads (dirt road);
- rerouted and engineered desert dry wash; and
- perimeter fencing.

Please see **Project Description Figures 4, 5 and 6**.

WATER DEMAND AND SOURCE OF SUPPLY

If built as proposed, the project would consume approximately 1,600 acre-feet of potable water per year. There are 12 existing water supply wells that were previously used to support alfalfa farming on the project site. As shown on **Project Description Figure 4**, the applicant proposes that four of these wells (Nos. 41, 42, 49, and 63) be used to supply the project's water needs. The wells draw water from a lower aquifer at a depth of approximately 600 feet below ground surface. The most significant demand for water would be the proposed wet cooling tower. Additional water would be required for make-up to the solar thermal and steam turbine system, washing of solar reflectors and collectors, potable water needs, and fire protection. The water is expected to be treated on site using a package water treatment system. The treatment system would be comprised of equipment for filtering, softening, de-mineralizing, and sanitizing the raw water.

WASTEWATER

The BSEP would have two types of wastewater streams. The primary wastewater stream would come from cooling tower *blowdown* and be piped to on-site evaporation ponds where the solids would settle to the bottom and the water would evaporate. The applicant proposes to collect and dispose of the accumulated solids at the end of the plant's operational life in approximately 40 years.

NATURAL GAS PIPELINE

The two auxiliary boilers would require the installation of a new 17.6-mile natural gas supply line. The supply line would be installed underground, in the right of way of Neuralia Road, heading south to California City Boulevard and then west to the Southern California Gas Company (SCG) natural gas tie-in point, just east of the Union Pacific Railroad tracks (see **Project Description Figure 2**). Pipeline construction would take approximately six months and employ a peak workforce of approximately 240 workers.

AIR POLLUTION CONTROL

Air pollution emissions from the combustion of natural gas in the auxiliary boilers would be controlled using the best available control technology (BACT). To ensure that the systems perform correctly, continuous emission monitoring for nitrogen oxides (NO_x), carbon monoxide (CO), and other pollutants would be performed. The natural gas consumption is estimated at 60 million British thermal units per hour (MMBtu/hr) for a maximum of 36,000 MMBtu/hr.

HAZARDOUS WASTE MANAGEMENT

Several methods would be used to properly manage and dispose of hazardous wastes. Waste lubricating oil would be recovered and recycled by a waste oil recycling contractor. Chemicals would be stored in appropriate chemical storage facilities. Bulk chemicals would be stored in large storage tanks, while most other chemicals would be stored in smaller returnable delivery containers. All chemical storage areas would be designed to contain leaks and spills in concrete containment areas. The applicant would have an approved Risk Management Plan in place to deal with any potential problems related to the use and handling of hazardous waste.

FIRE PROTECTION

The fire protection system would be designed to protect personnel and limit property loss and plant downtime in the event of a fire. The primary source of fire protection water would be the raw water storage tank. An electric jockey pump and electric motor-driven main fire pump would be provided to increase the water pressure to the level required to serve all fire fighting systems. In addition, a backup diesel engine-driven fire pump would be provided to pressurize the fire loop if the power supply to the electric motor-driven main fire pump fails.

Fire support services to the site would be under the jurisdiction of the Kern County Fire Department (KCFD). Station 14 is 19 miles from the project site, located at 1953 Highway 58, Mojave, California, and would be the first responder to BSEP with a response time of approximately 23 minutes. Kern County Fire Department also has mutual aid agreements with California City Fire Department and Edwards Air Force Base for responses requiring more assistance.

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.

TRANSMISSION SYSTEM INTERCONNECTION AND UPGRADES

The proposed BSEP project would be located approximately 1.5 miles north of the 230 kilovolt (kV) Barren Ridge Switching Stationed owned by the Los Angeles Department of Water and Power (LADWP). The BSEP project would interconnect to the Barren Ridge Switching Station as the primary point of interconnection (POI). According to an LADWP Systems Impact Study (SIS), dated July 31, 2008, the proposed primary POI configuration has demonstrated acceptable system performance, and system additions would be provided solely for the BSEP primary POI configuration at the Barren Ridge Switching Station (DB 2008l).

The new interconnection would be made by using one of two optional routes. Option 1 route would be approximately 3.5 miles in length, and Option 2 route would be approximately 2.3 miles in length. Option 2 would include a new switching station to be located adjacent to the LADWP transmission line corridor. Under either option, the interconnection would be made by installing a new 230-kV line using up to 39 concrete monopoles. Each monopole would average 79 feet in height and be spaced approximately 500 feet apart (see **Project Description Figure 4**).

LADWP is currently proposing the Barren Ridge Renewable Transmission Project (BRRTP), which will include upgrades and building a new transmission line from Barren Ridge Switching Station to Castaic Power Plant near Santa Clarita. The upgrade is meant to serve new renewable power generation projects in the Mojave Desert and Tehachapi Mountain areas. However, as stated above, the BSEP project is not dependant on the BRRTP improvements.

TELECOMMUNICATIONS FACILITIES

The BSEP will require telecommunications services although it is not clear at this time what the scope of offsite improvements will be related to providing telecommunications infrastructure.

PROJECT CONSTRUCTION AND OPERATION

If approved by the Energy Commission, the applicant proposes to begin project construction during the third quarter of 2009, conduct start-up and testing during second quarter of 2011, and bring the facility on line during the third quarter of 2011. Project construction is estimated to take 25 months to complete, with an average workforce of

477 employees and a peak workforce of approximately 836 workers. Development and construction is expected to cost approximately $950 million. Typical operating hours for the project would be an average of approximately 12 hours per day equating to an annual average of 4,380 hours per year (DB 2008l).

FACILITY CLOSURE

The BSEP would be designed for an operating life of up to 40 years. Depending on maintenance factors, at an appropriate point beyond the designed operating life, 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.

Although the setting for this project does not appear to present any special or unusual closure problems, it is impossible to foresee what the situation would be in 40 years or more when the project ceases operation. Therefore, provisions must be made which provide the flexibility to deal with the specific situation and project setting at the time of closure. Facility closure would be consistent with laws, ordinances, regulations, and standards in effect at the time of closure.

REFERENCES

BS 2008a - FPL Energy/M. O'Sullivan (tn 45646). Application for Certification, dated 03/13/08. Submitted to CEC/Docket Unit on 03/14/08.

BS 2008c - Beacon Solar, LLC/G. Palo (tn 45972). AFC Volume 3 - Data Adequacy Supplement, dated 04/18/08. Submitted to CEC/Docket Unit on 04/21/08.

BS 2008f – FLP Energy (tn 46698). CEC Informational Hearing - Applicant's Slide Presentation, dated 06/11/08. Submitted to CEC/Docket Unit on 06/16/08.

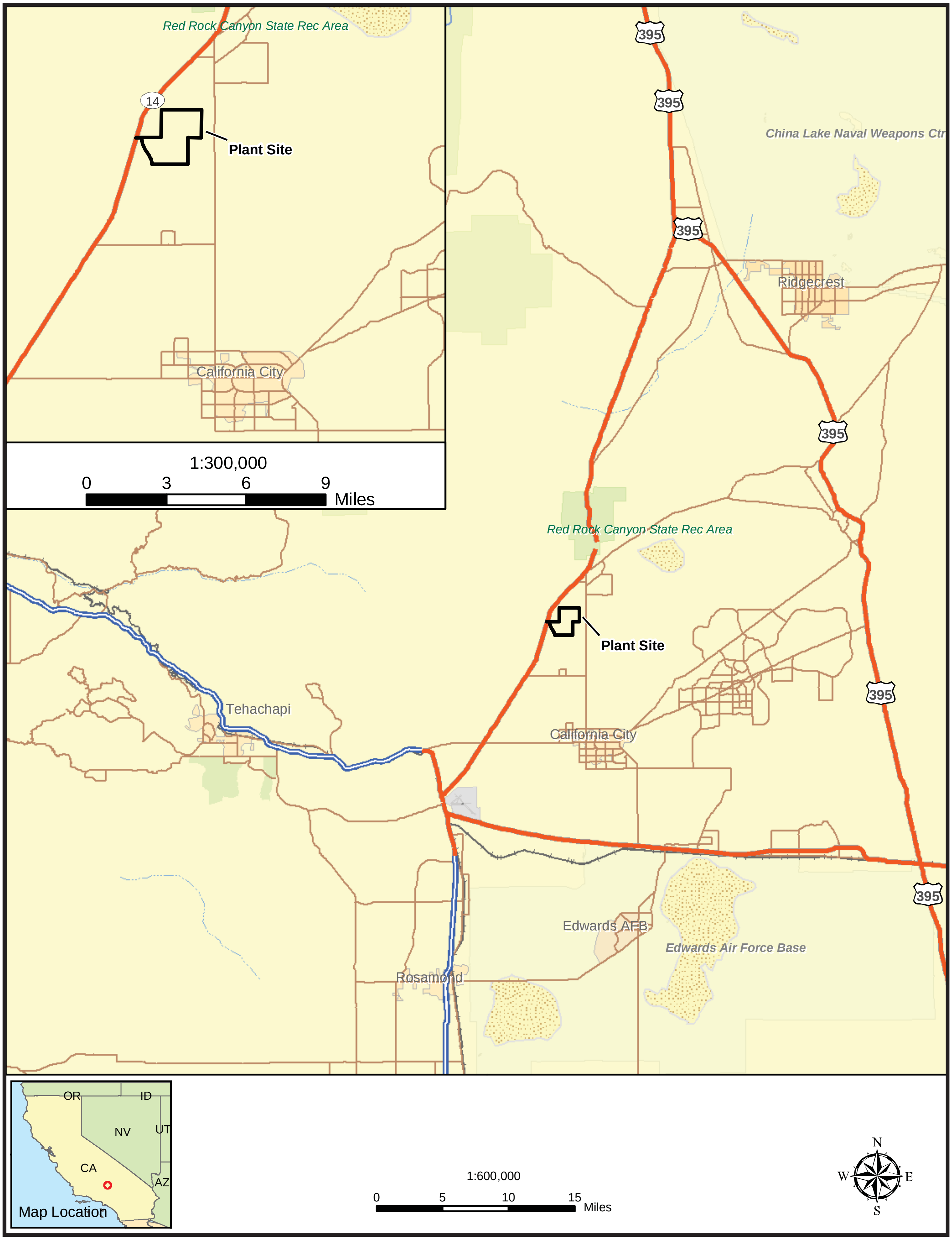
BS 2008h - Beacon Solar, LLC/M. Argentine (tn 48141). Applicant's Response to Questions from Rancho Seco Residents, dated 09/19/08. Submitted to CEC/Docket Unit on 09/22/08.

BS 2008i – Beacon Solar, LLC/M. Russell (tn 49439). Beacon Responses to Question Set #2 From Rancho Seco Residents, dated 12/05/2008. Submitted to CEC/Docket Unit on 12/17/08.

DB 2008l - Downey Brand/J. Luckhardt (tn 47885). Responses to Data Requests 50-52, dated 09/02/08. Submitted to CEC/Docket Unit on 09/02/08.

PROJECT DESCRIPTION - FIGURE 1

Beacon Solar Energy Project - Regional and Vicinity Map

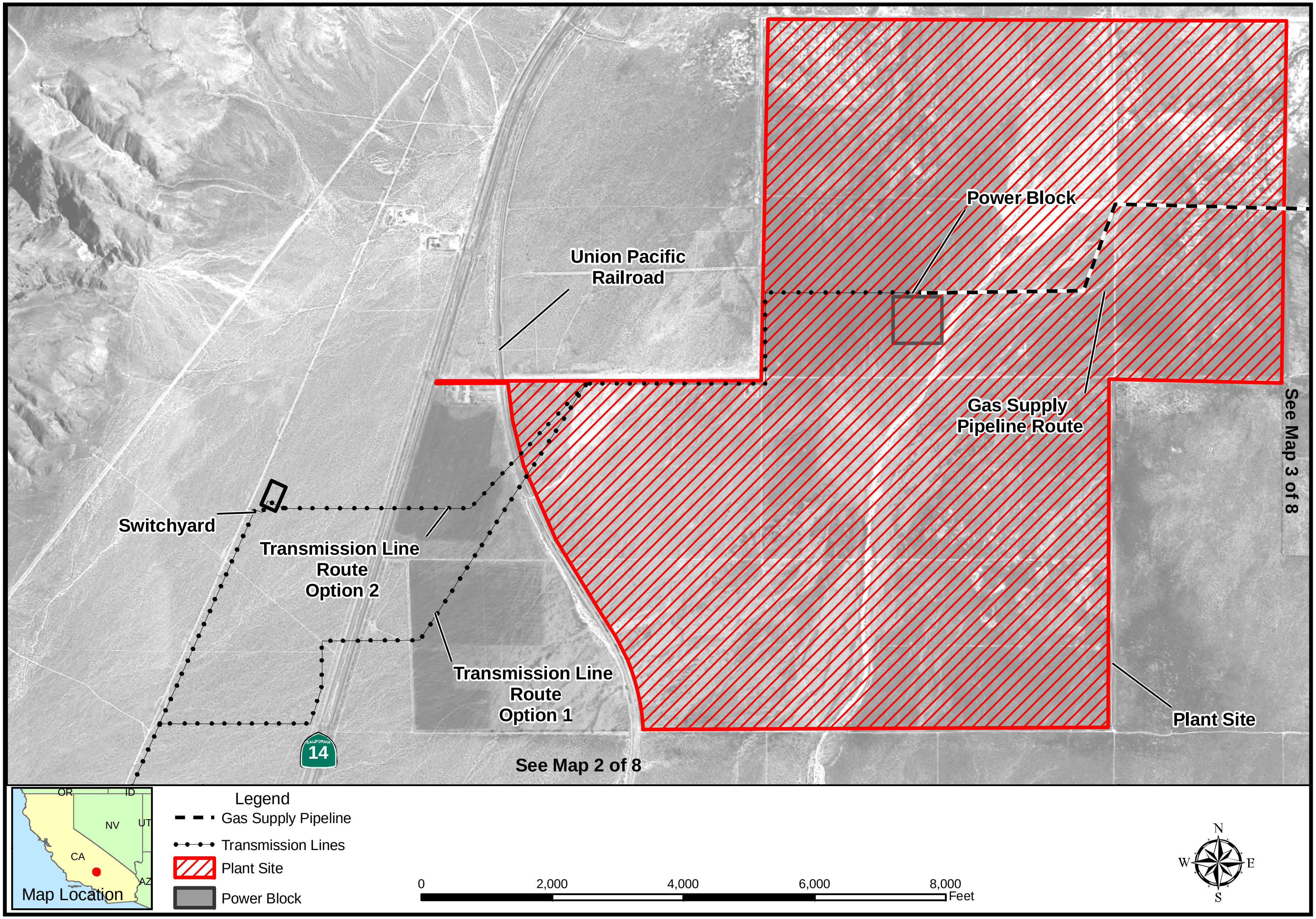


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

AFC Figure 1-1

PROJECT DESCRIPTION - FIGURE 2a

Beacon Solar Energy Project - Project Site and Linear Facilities - Map 1 of 8

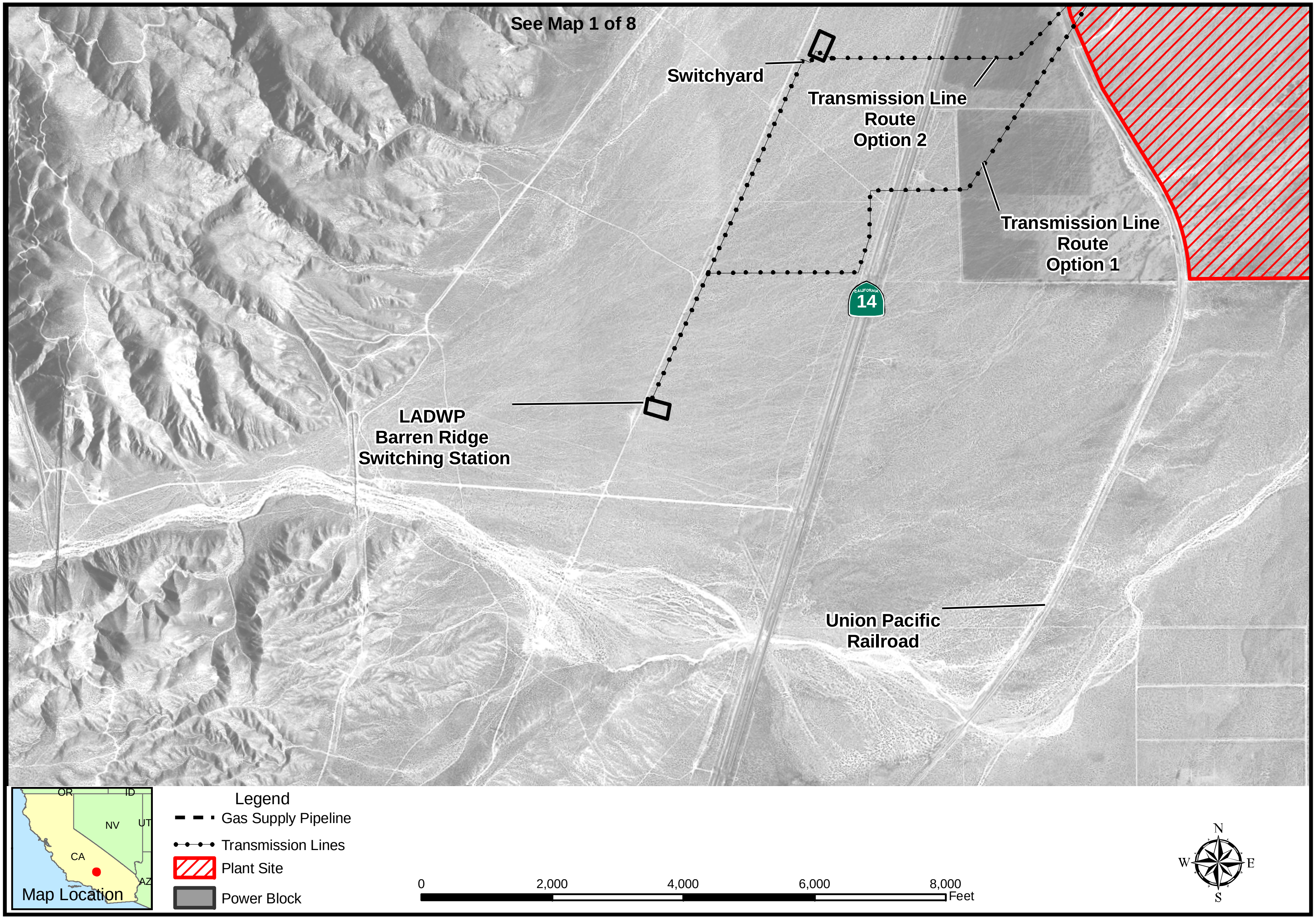


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: AFC Figure 2-1 Mapsheet 1 of 8

PROJECT DESCRIPTION - FIGURE 2b

Beacon Solar Energy Project - Project Site and Linear Facilities - Map 2 of 8

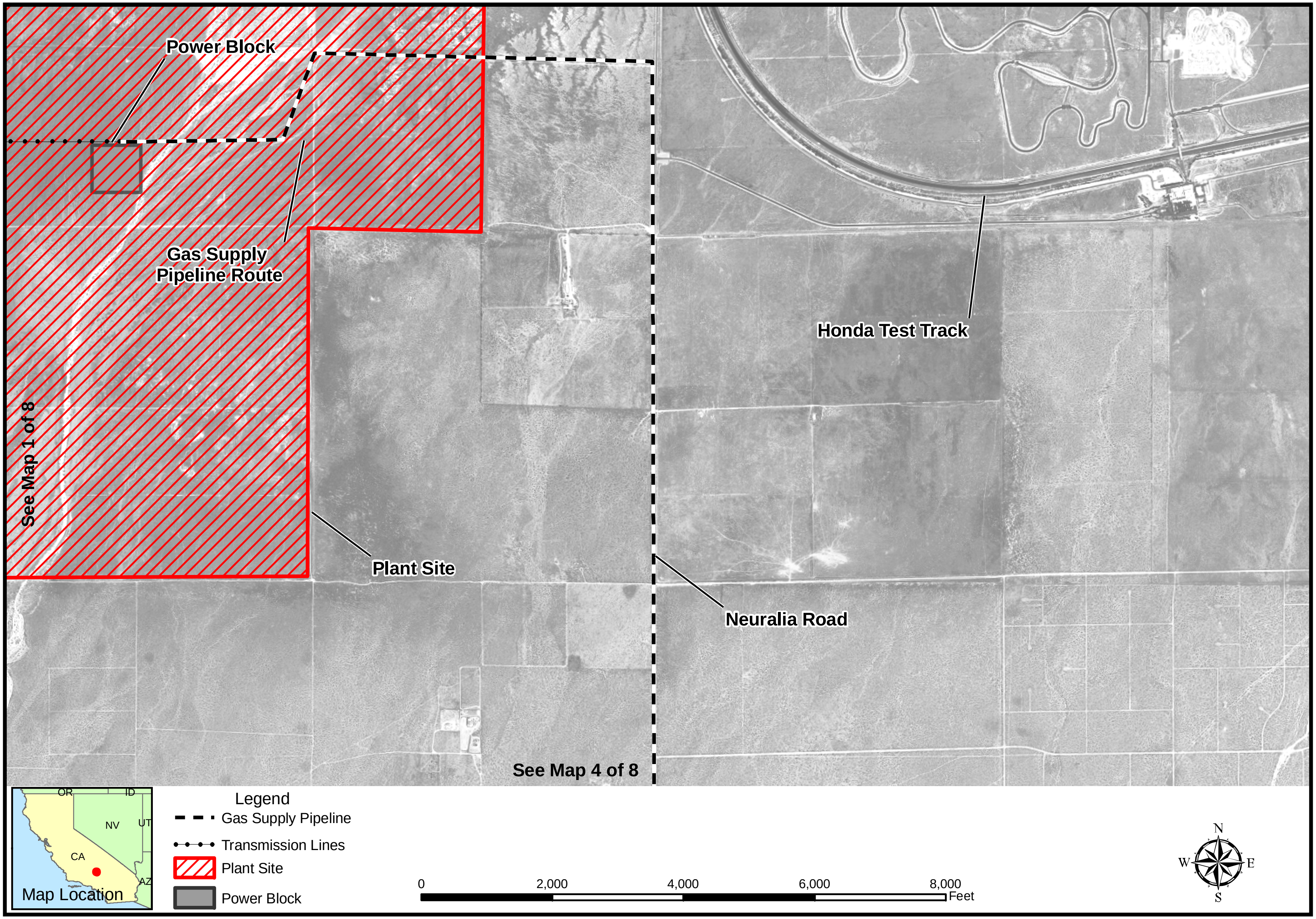


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: AFC Figure 2-1 Mapsheet 2 of 8

PROJECT DESCRIPTION - FIGURE 2c

Beacon Solar Energy Project - Project Site and Linear Facilities - Map 3 of 8



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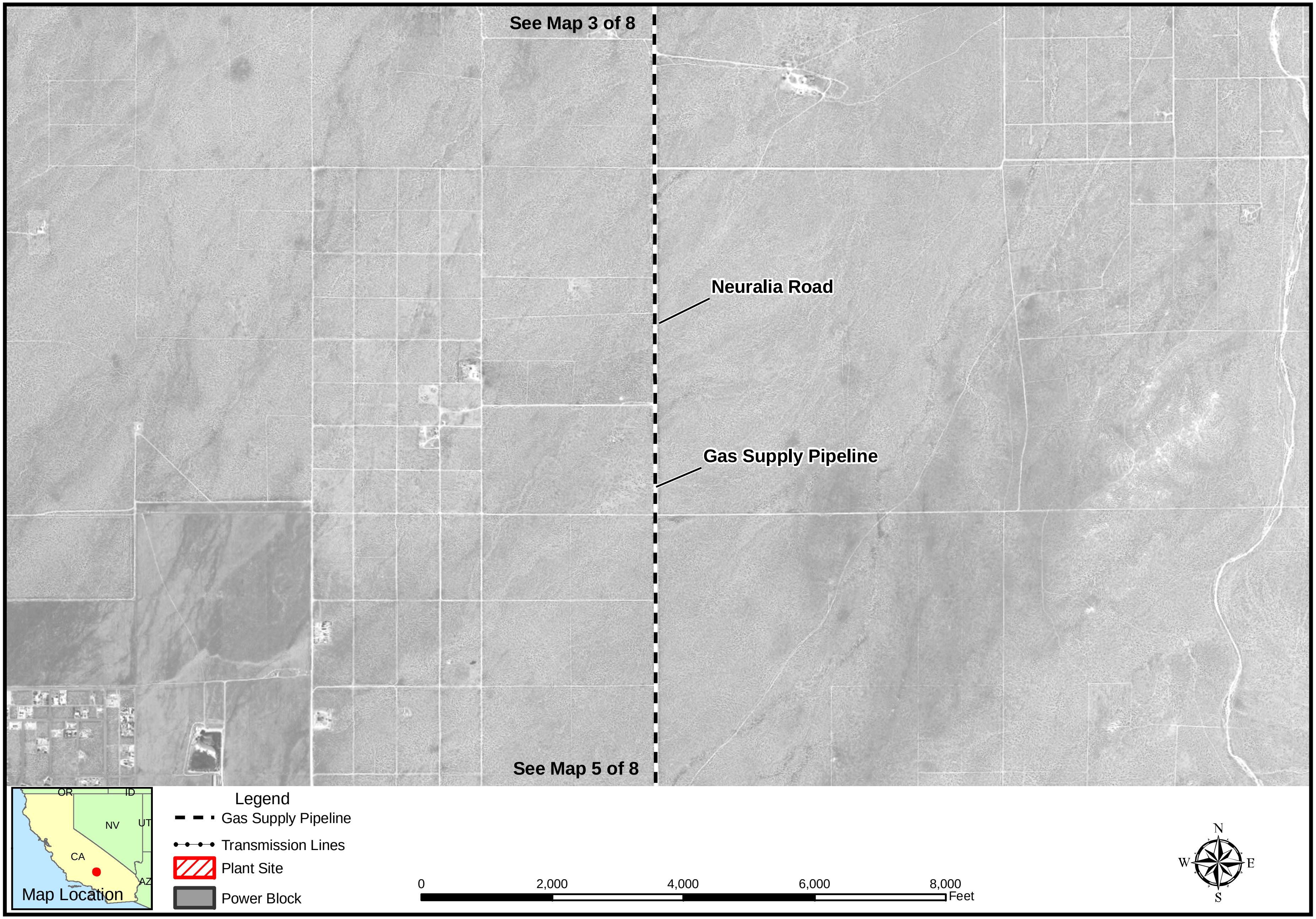
SOURCE: AFC Figure 2-1 Mapsheet 3 of 8

PROJECT DESCRIPTION - FIGURE 2d

Beacon Solar Energy Project - Project Site and Linear Facilities - Map 4 of 8



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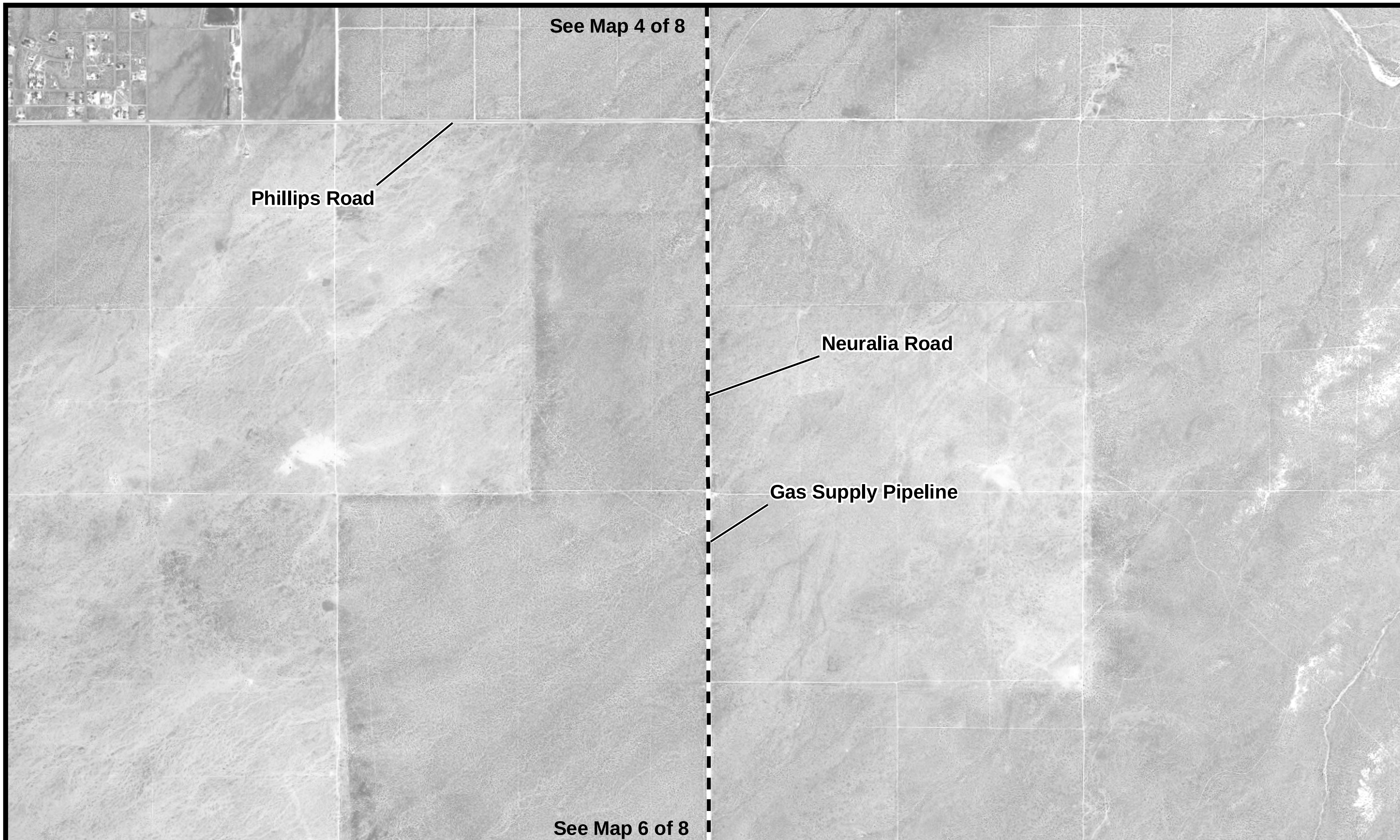
SOURCE: AFC Figure 2-1 Mapsheet 4 of 8

PROJECT DESCRIPTION - FIGURE 2e

Beacon Solar Energy Project - Project Site and Linear Facilities - Map 5 of 8



Legend
- Gas Supply Pipeline
- Transmission Lines
- Plant Site
- Power Block

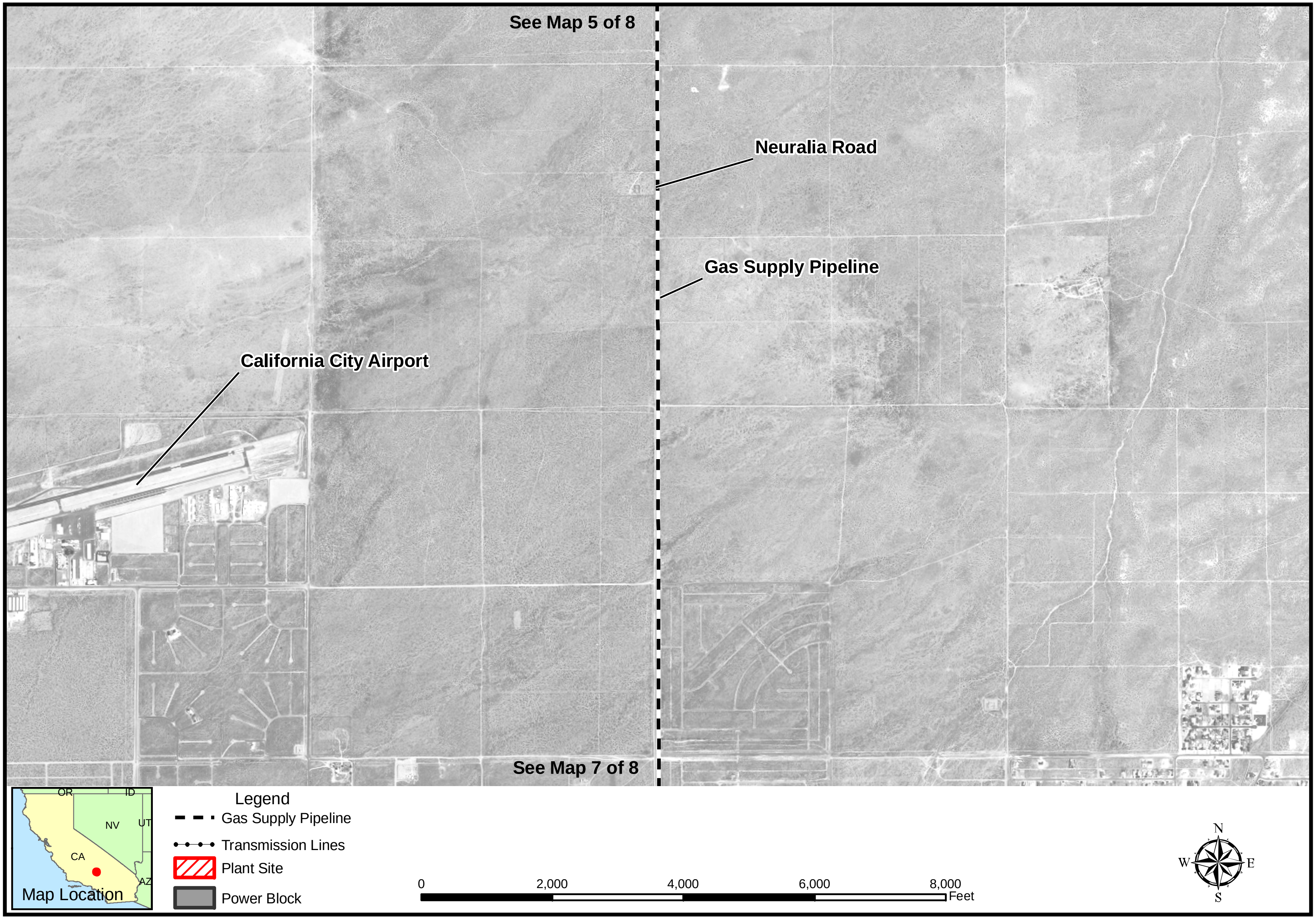
0 2,000 4,000 6,000 8,000 Feet

N S E W

SOURCE: AFC Figure 2-1 Mapsheet 5 of 8

PROJECT DESCRIPTION - FIGURE 2f

Beacon Solar Energy Project - Project Site and Linear Facilities - Map 6 of 8

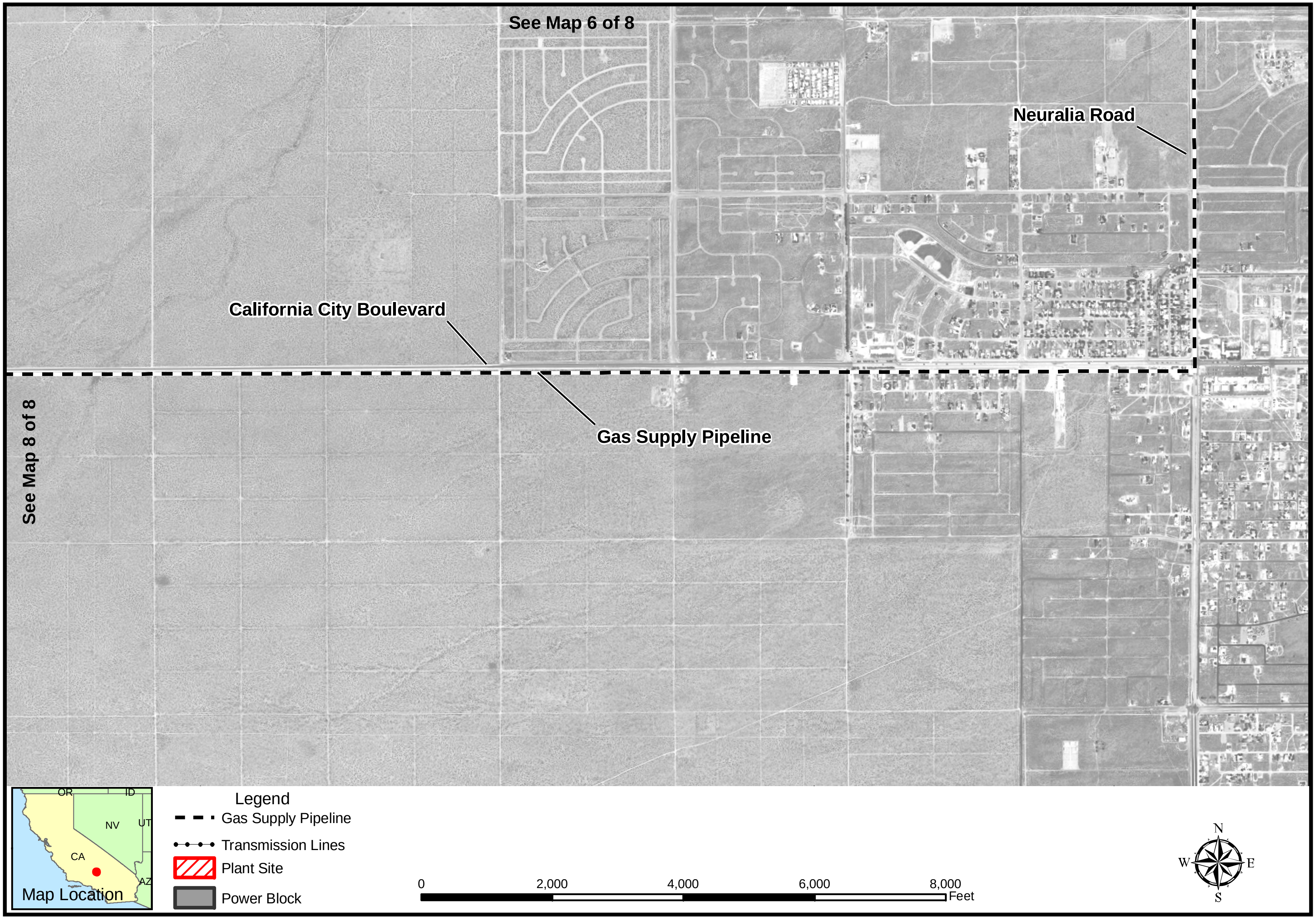


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: AFC Figure 2-1 Mapsheet 6 of 8

PROJECT DESCRIPTION - FIGURE 2g

Beacon Solar Energy Project - Project Site and Linear Facilities - Map 7 of 8

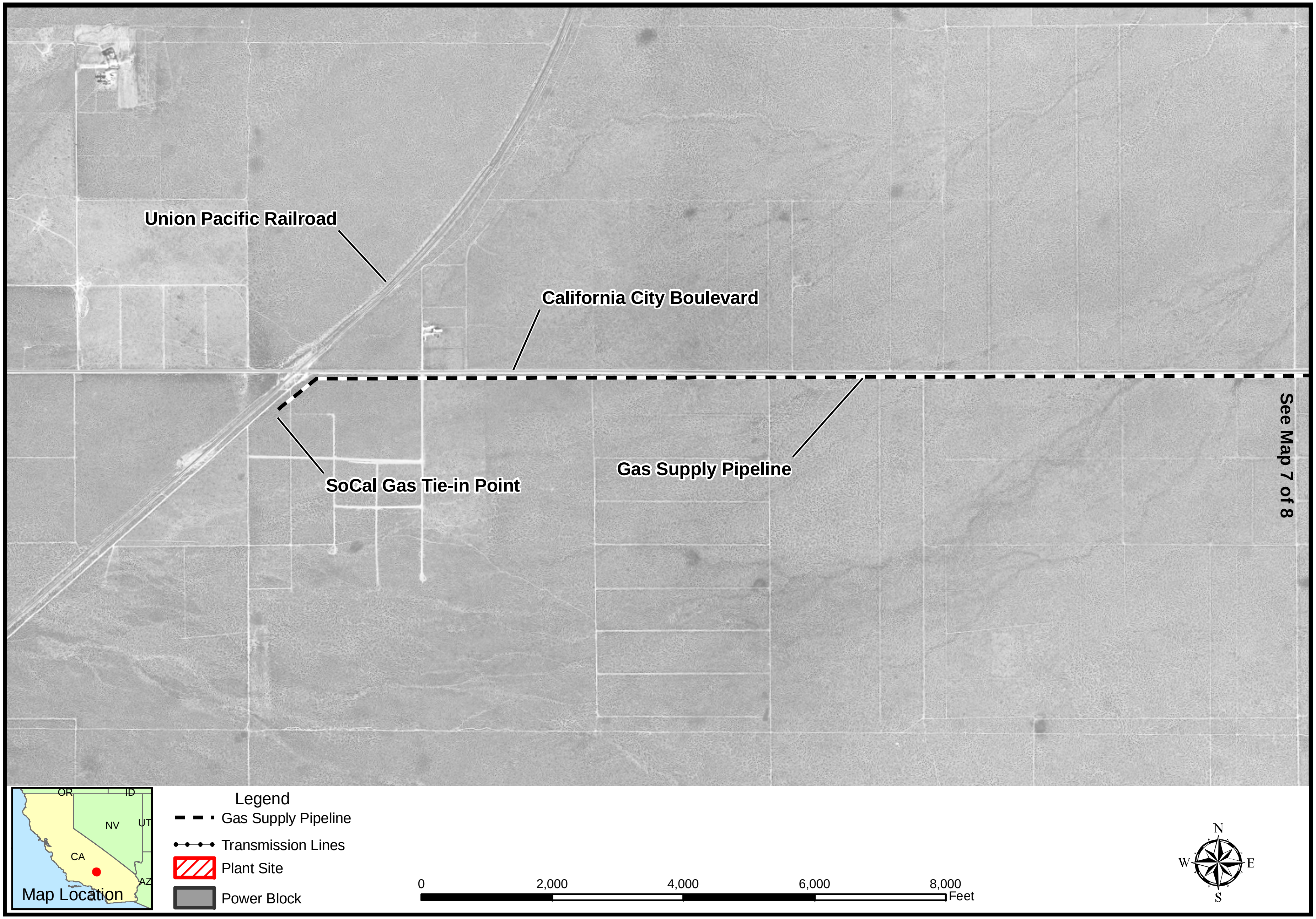


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: AFC Figure 2-1 Mapsheet 7 of 8

PROJECT DESCRIPTION - FIGURE 2h

Beacon Solar Energy Project - Project Site and Linear Facilities - Map 8 of 8



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SOURCE: AFC Figure 2-1 Mapsheet 8 of 8

PROJECT DESCRIPTION - FIGURE 3
Beacon Solar Energy Project - Plant Site Photographs - Existing Conditions

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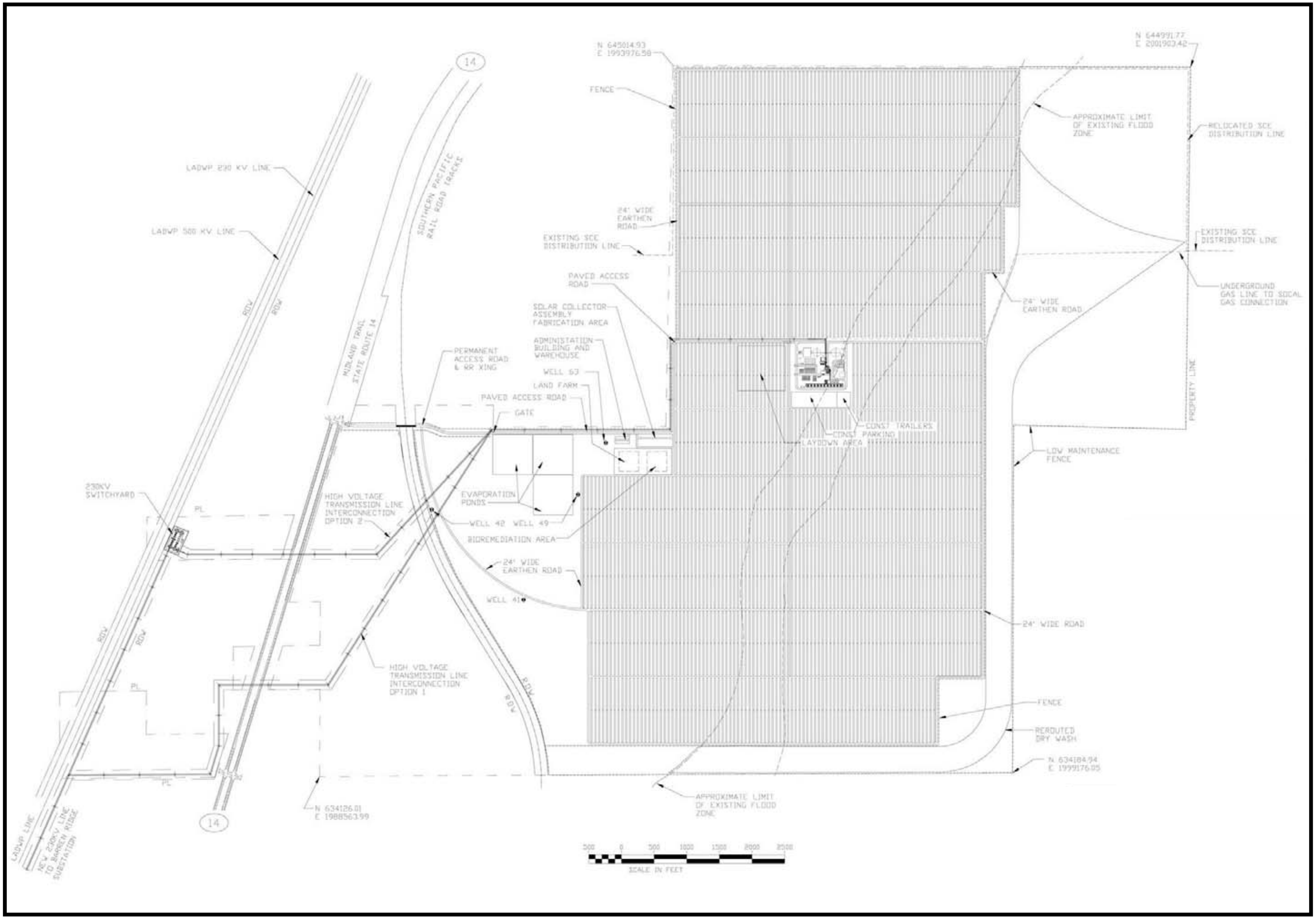
SOURCE: AFC Figure 2-2

PROJECT DESCRIPTION - FIGURE 4

Beacon Solar Energy Project - General Arrangement Site Plan



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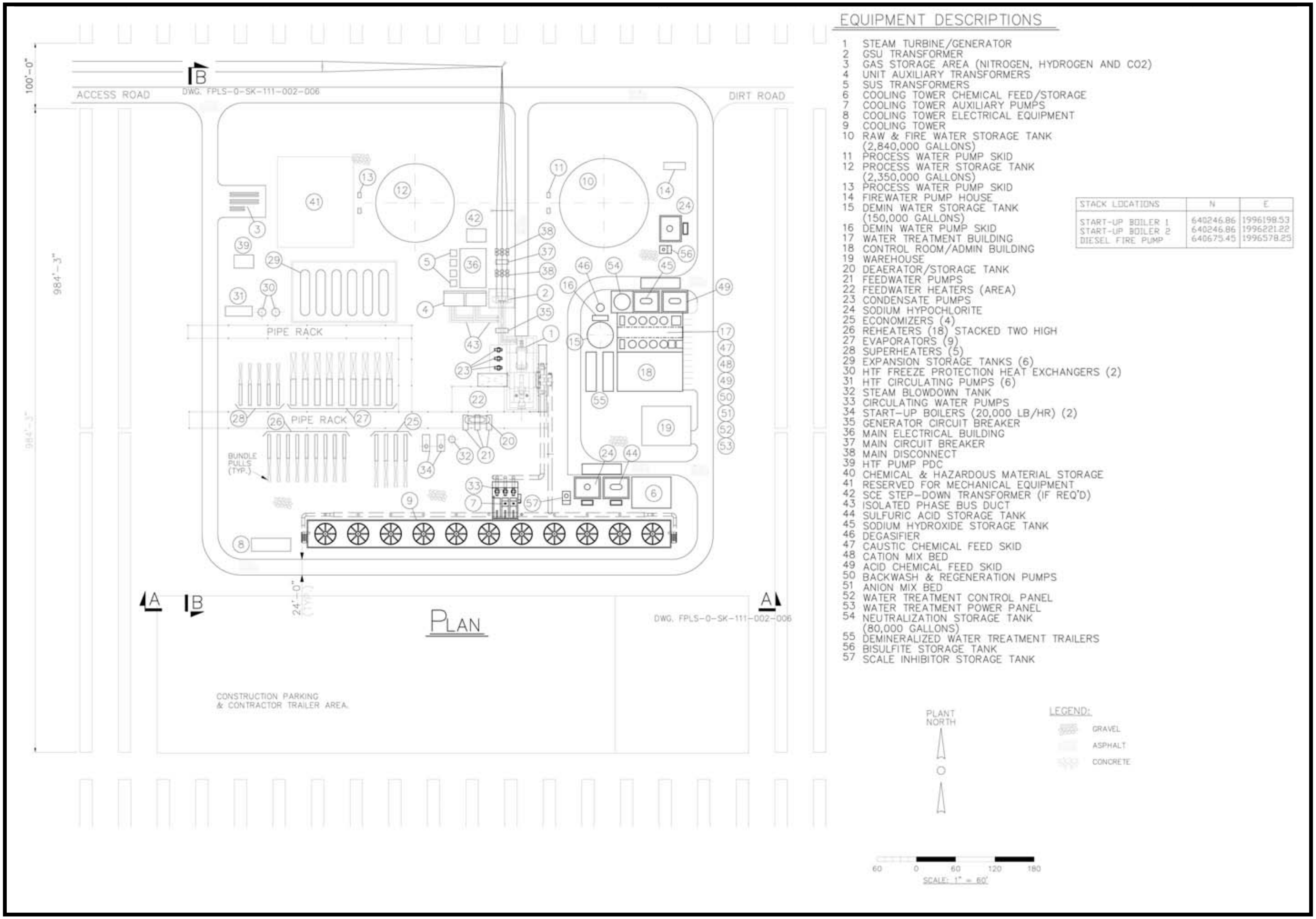
SOURCE: AFC Figure 2-4

PROJECT DESCRIPTION - FIGURE 5

Beacon Solar Energy Project - General Arrangement Power Block Equipment Layout

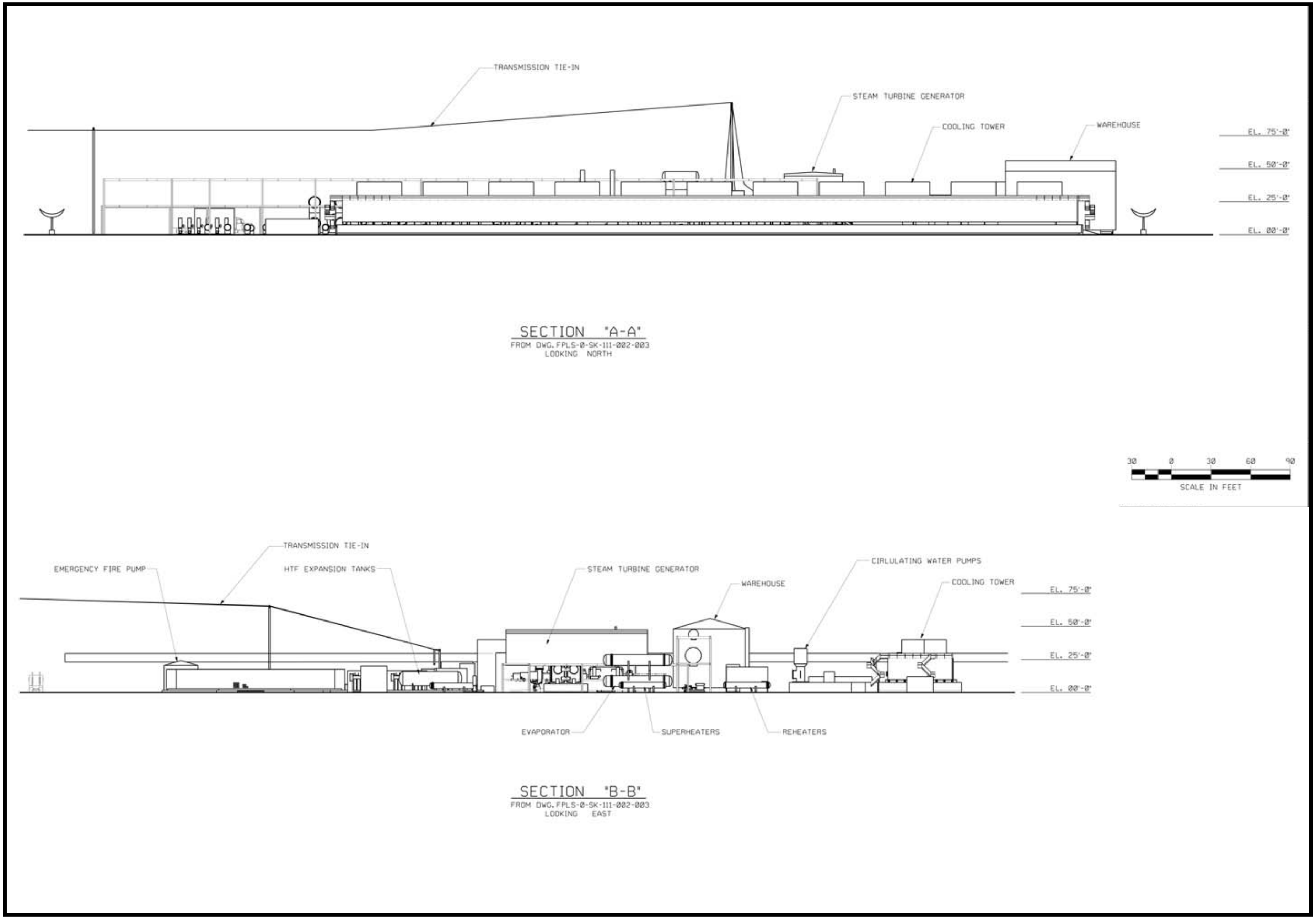


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: AFC Figure 2-5

PROJECT DESCRIPTION - FIGURE 6

Beacon Solar Energy Project - General Arrangement Power Block Elevation Views



SOURCE: AFC Figure 2-6

PROJECT DESCRIPTION - FIGURE 7
Beacon Solar Energy Project - Typical Trough Solar Collector

SOURCE: AFC Figure 2-8

ENVIRONMENTAL ASSESSMENT

AIR QUALITY

William Walters, P.E.

SUMMARY OF CONCLUSIONS

Staff finds that with the adoption of the attached conditions of certification the proposed Beacon Solar Energy Project (BSEP or Beacon) would comply with all applicable laws, ordinances, regulations, and standards (LORS) and would not result in any significant air quality-related impacts.

The BSEP project would emit significantly reduced greenhouse gas (GHG)[1] emissions per megawatt-hour produced than fossil fueled generation resources in California. The project is not subject to the requirements of SB 1368 (Perata, Chapter 598, Statutes of 2006) and the Emission Performance Standard, but would nevertheless comply with the Emission Performance Standard.

INTRODUCTION

Beacon Solar LLC, a wholly owned subsidiary of FPL Energy, LLC, submitted an Application for Certification (AFC) to construct and operate a solar power plant in the Mojave Desert. The approximately 2,012-acre Project plant site is located in eastern Kern County along the California State Route 14 (SR-14) corridor, approximately four miles north-northwest of California City's northern boundary, approximately 15 miles north of the Town of Mojave, and approximately 24 miles northeast of the City of Tehachapi. The project would be a concentrated solar electric generating facility comprised of parabolic trough solar collectors and would include two auxiliary natural gas fueled-boilers with a new 17.6-mile, eight-inch gas pipeline for fueling the two boilers. The facility is expected to produce a nominal electrical output of 250 megawatts (MW).

This analysis evaluates the expected air quality impacts from the emissions of criteria air pollutants from both the construction and operation of the Beacon Solar Energy Project. Criteria air pollutants are defined as air contaminants that the state and/or federal governments have established an ambient air quality standard to protect public health.

The criteria pollutants analyzed are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), and particulate matter (PM). Two subsets of particulate matter are inhalable particulate matter (less than 10 microns in diameter - PM10) and fine particulate matter (less than 2.5 microns in diameter - PM2.5). Nitrogen oxides (NOx, consisting primarily of nitric oxide (NO) and NO_2) and volatile organic compounds (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. Global climate change

[1] Greenhouse gas emissions are not criteria pollutants, but they affect global climate change. In that context, staff evaluates the GHG emissions from the proposed project (Appendix Air-1), presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

and greenhouse gas (GHG) emissions from the project are discussed in an Appendix Air-1 and analyzed in the context of cumulative impacts.

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

- whether the BSEP is likely to conform with applicable federal, state, and Kern County Air Pollution Control District (District) air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1744 (b));
- whether the BSEP is likely to cause new violations of ambient air quality standards or contribute substantially to existing violations of those standards (Title 20, California Code of Regulations, section 1743); and
- whether mitigation measures proposed for the project are adequate to lessen potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

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

Air Quality Table 1
Laws, Ordinances, Regulations, and Standards

Applicable LORS	Description
Federal	
40 Code of Federal Regulations (CFR) Part 52	Nonattainment New Source Review (NSR) requires a permit and requires Best Available Control Technology (BACT) and Offsets. Permitting and enforcement delegated to KCAPCD. Prevention of Significant Deterioration (PSD) requires major sources or major modifications to major sources to obtain permits for attainment pollutants. The BSEP is a new source thus the PSD trigger levels are 250 tons per year for NOx, VOC, SOx, PM10, PM2.5 and CO.
40 CFR Part 60	New Source Performance Standards (NSPS), Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Establishes emission standards for compressions ignition internal combustion engines, including emergency fire water pump engines.
State	
Health and Safety Code (HSC) Section 40910-40930	Permitting of source needs to be consistent with Air Resource Board (ARB) approved Clean Air Plans.
HSC Section 41700	Restricts emissions that would cause nuisance or injury.
California Code of Regulations (CCR) Section 93115	Airborne Toxics Control Measure for Stationary Compression Ignition Engines. Limits the types of fuels allowed, established maximum emission rates, establishes recordkeeping requirements on stationary compression ignition engines, including emergency fire water pump engines.

Applicable LORS	Description
Local (KCAPCD)	
Rule 201 - Permits Required	Establishes the requirement to obtain a permit to Operate (PTO) for emission sources.
Rule 210.1 - New and Modified Stationary Source Review	Establishes the requirements that must be met to obtain a PTO, including the requirement to comply with best available control technology (BACT), provide emission offsets for emission increase above specified thresholds, provide a dispersion modeling analysis, an alternatives analysis, and a compliance certification (if applicable).
Rule 401 - Visible Emissions	Limits visible emissions from emissions sources, including stationary source exhausts and fugitive dust emission sources.
Rule 402 - Fugitive Dust	Limits fugitive emissions from certain bulk storage, earthmoving, construction and demolition, and manmade conditions resulting in wind erosion.
Rule 404.1 - Particulate Matter Concentration	The rule limits particulate matter (PM) emissions to less than 0.1 grains per standard cubic foot of gas at standard conditions.
Rule 407 - Sulfur Compounds	Limits discharge into the atmosphere of sulfur compounds exceeding 0.2% by volume concentration calculated as SO_2.
Rule 409 - Fuel Burning Equipment - Combustion Contaminants	Limits discharge into the atmosphere from fuel burning equipment combustion contaminants exceeding in concentration at the point of discharge, 0.1 grain per cubic foot of gas calculated to 12% of carbon dioxide (CO_2) at standard conditions.
Rule 411 – Storage of Organic Liquids	Sets standards for storage of organic liquids with a true vapor pressure of 1.5 pounds per square inch or greater.
Rule 414.2 – Soil Decontamination	Sets requirements for the VOC emissions from the handling and decontamination activities of VOC contaminated soils.
Rule 419 - Nuisance	Restricts emissions that would cause nuisance or injury to people or property (identical to California Health and Safety Code 41700.
Rule 422 - New Source Performance Standards	Incorporates the Federal NSPS (40 CFR 60) rules by reference.
Rule 425.2 - Boilers, Steam Generators and Process Boilers (Oxides of Nitrogen)	This rule limits NOx emissions from boilers, steam generators, and process heaters to levels consistent with Reasonably Available Control Technology (RACT).
Rule 429.1 - Cooling Towers (Hexavalent Chromium)	Prohibits the use of hexavalent chromium-bearing compounds in cooling towers

SETTING

CLIMATE AND METEOROLOGY

The proposed BSEP site located in the Mojave Desert is relatively flat, with elevations ranging from approximately 2,220 feet above mean sea level (amsl) in the southwest to 2,025 feet amsl in the northeast. The Mojave Desert has a typical desert climate, having extreme daily temperature changes, low annual precipitation, strong seasonal winds, and mostly clear skies. The annual highest temperature in the Mojave Desert exceeds 100°F and the average daily temperature variation is approximately 30 degrees in the summer and 25 degrees in the winter. Winter temperatures are more moderate, with mean maximum temperatures in the 60s and lows in the 30s. Nearby California City has a total average annual precipitation of less than seven inches (WC 2008). Over 70% of the precipitation occurs in the winter season, between December and March. However, occasional heavy precipitation occurs in the summer due to thunderstorms.

The applicant collected recent (2002 to 2004) meteorological data from the Mojave-Poole Street monitoring station, located approximately 17 miles south of the BSEP site. The average annual wind rose for these three years at this monitoring station shows a prevailing wind from west to northwest occurring approximately 45% of the time, and a second prominent winds direction from the southwest and west-southwest occurring 25% of the time. Considering the topography near the project site it is likely that the winds from the southwest and west-southwest are somewhat more prominent than at Mojave.

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 (USEPA). 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 $\mu g/m^3$, 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 (NO_2)	Annual	0.053 ppm (100 µg/m^3)	0.03 ppm (57 µg/m^3)
	1 Hour	—	0.18 ppm (339 µg/m^3)
Sulfur Dioxide (SO_2)	Annual	0.030 ppm (80 µg/m^3)	—
	24 Hour	0.14 ppm (365 µg/m^3)	0.04 ppm (105 µg/m^3)
	3 Hour	0.5 ppm (1300 µg/m^3)	—
	1 Hour	—	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 2008a.

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 non-attainment 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 non-attainment, 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 non-attainment for another, or attainment for the federal standard and non-attainment for the state standard for the same air contaminant.

The project site is located in the Mojave Desert Air Basin[2] and is under the jurisdiction of the Kern County Air Pollution Control District. The Kern County portion of the Mojave Air Basin is designated as non-attainment for the state ozone standards, the federal 8-hour ozone standard, and the state PM10 standards. This area is designated as attainment or unclassified for the state and federal CO, NOx, SOx, and PM2.5 standards and the federal PM10 standard. **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
Kern County Portion of the Mojave Desert Air Basin

Pollutant	Attainment Status [a]	
	Federal	State
Ozone	Moderate Nonattainment [b]	Moderate Nonattainment
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
PM10	Attainment	Nonattainment
PM2.5	Attainment	Attainment

Source: ARB 2008b, U.S. EPA 2008.
[a] Attainment = Attainment or Unclassified.
[b] Kern County is in the process of being re-classified to moderate nonattainment of the federal 8-hour state ozone standard.

Ambient air quality monitoring data for ozone, PM10, PM2.5, CO, NO_2, and SO_2, compared to most restrictive applicable standards for the years between 2002 through 2007 (the last year that the complete annual data is currently available) at the most representative monitoring stations for each pollutant are shown in **Air Quality Table 4** and the 1-hour and 8-hour ozone, and 24-hour PM10 data for the years 1996 through 2007 are shown in **Air Quality Figure 1**. All ozone, PM10 and PM2.5 data shown are from Mojave-923 Poole Street monitoring station. All CO data are from the Lancaster-43301 Division Street monitoring station. NOx data for the years 2002-2004 are from the Mojave-923 Poole Street monitoring station and for the years 2005-2007 are from the Trona Athol and Telegraph monitoring station. All 24-hour SOx data are from the Trona Athol and Telegraph monitoring station.

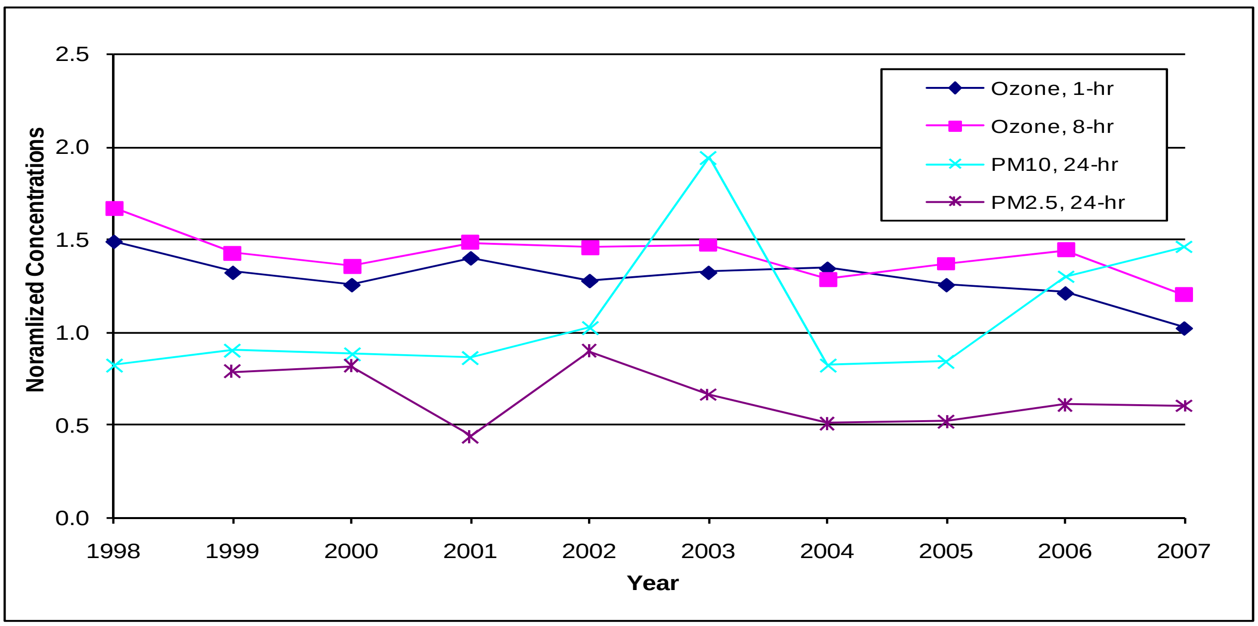
[2] The Mojave Desert Air Basin lies inland east of the San Joaquin Valley Air Basin to the west and north and east of the South Coast Air Basin. The desert portions of Kern, San Bernardino, Riverside, and Los Angeles counties are within its boundaries.

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

Pollutant	Averaging Period	Units	2002	2003	2004	2005	2006	2007	Limiting AAQS
Ozone	1 hour	ppm	0.115	0.119	0.121	0.113	0.109	0.092	0.09
Ozone	8 hours	ppm	0.102	0.103	0.090	0.096	0.101	0.084	0.07
PM10 [a]	24 hours	μg/m^3	208	97.0	41.0	42.0	65.0	73.0	50
PM10	Annual	μg/m^3	21.4	19.3	18.3	--	19.5	--	20
PM2.5 [a,b]	24 hours	μg/m^3	31.4	23.2	17.8	18.1	21.3	21.1	35
CO	1 hour	ppm	3.4	3.2	2.9	2.9	3.2	--	20
CO	8 hours	ppm	2.24	1.88	1.72	1.54	1.60	1.25	9.0
NO_2	1 hour	ppm	0.071	0.073	0.064	0.053	0.050	0.055	0.18
NO_2	Annual	ppm	0.009	0.009	0.008	0.005	0.004	0.004	0.03
SO_2	1 hour	ppm	0.012	0.008	0.019	0.018	0.033	--	0.25
SO_2	24 hours	ppm	0.007	0.003	0.005	0.004	0.004	0.005	0.04
SO_2	Annual	ppm	0.001	0.001	0.001	0.001	0.001	0.001	0.03

Source: ARB 2008c, ARB 2008d
Notes:
[a] Exceptional PM concentration events, such as those caused by wind storms may be included in the data presented.
[b] Annual average PM2.5 data is not available from the Mojave Poole Street monitoring station.

Air Quality Figure 1
1998-2007 Historical Ozone and PM Air Quality Data
Mojave Desert Air Basin



Source: ARB 2008c
Note: The exceptional PM10 event in 2002, believed to be caused by a wind storm or other natural phenomena, was replaced by the second highest concentration monitored in 2002. The highest measured ambient concentrations of various criteria air contaminants were divided by their applicable standard and provided as a graphical point. Any point on the chart that is greater than one means that the measured concentrations of such air contaminant exceed the standard, and any point that is less than one means that the respective standard is not exceeded for that year. For example the 1-hour ozone concentration in 1998 is 0.134 ppm/0.09 ppm standard = 1.49.

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. In general, the Western MDAB's elevated ozone concentrations are due to pollutant transport from the South Coast Air Basin (Los Angeles Area) and the San Joaquin Valley.

As **Air Quality Table 4** and **Air Quality Figure 1** indicate, the 1-hour and 8-hour ozone concentrations measured in Mojave have been slowly decreasing over time. The collected air quality data (not shown) indicate that the ozone violations occurred primarily during the sunny and hot periods typical during May through September.

Nitrogen Dioxide

The entire air basin is classified as attainment for the state and federal NO_2 standards. Approximately 90% 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.

Carbon Monoxide

The area 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 has 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 non-attainment for the state PM10 standards, and is attainment for the federal PM10 standard. As shown in **Air Quality Figure 1**, PM10 concentrations were slightly below the state 24-hour PM10 standard for seven years in the recent 12-year history. The peak concentrations from 2002 through 2007 occurred during every season, although three of the years had peak concentrations in late summer. However, the highest of the peak concentrations occurred in the other three seasons and are likely to be due in part to high wind events. **Air Quality Figure 1** also indicates increasing PM10 concentrations since 2004.

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 organic and inorganic compounds.

The Kern County portion of the Mojave Desert Air Basin is classified as attainment for both the state and the federal PM2.5 air quality standards, but not in attainment of the state PM10 standard. This divergence indicates that the ambient particulate matter levels are most likely due to localized fugitive dust sources, such as vehicles travel on unpaved roads, agricultural operations, or wind-blown dust.

Sulfur Dioxide

The entire air basin is classified as attainment for the state and federal SO_2 standards. Sulfur dioxide is typically emitted as a result of the combustion of a fuel containing sulfur. Sources of SO_2 emissions within the MDAB come from a wide variety of fuels: gaseous, liquid and solid; however, the total SO_2 emissions within the western MDAB are limited due to the limited number of major stationary sources and California's significant reduction in motor vehicle fuel sulfur content. The project area's SO_2 concentrations are well below the state and federal ambient air quality standards.

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 within the Mojave Desert Air Basin 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	103.6	339	31%
	Annual	9.5	57	17%
PM10	24 hour	73	50	146%
	Annual	19.5	20	98%
PM2.5	24 hour	17.8	35	57%
	Annual	6.2	12	52%
CO	1 hour	3,680	23,000	16%
	8 hour	1,778	10,000	18%
SO_2	1 hour	86.5	655	13%
	3 hour	77.8	1,300	6%
	24 hour	13.1	105	12%
	Annual	2.7	80	3%

Source: ARB 2008c, ARB 2008d, and Energy Commission Staff Analysis
Note: PM2.5 24-hour data shown in **Air Quality Table 4** are peak values; however, the standard is based on the three year average of the 98th percentile. The average of the available 98th percentile values from the period of 2005 to 2007 at the Mojave monitoring station was used as the basis for the PM2.5 24-hour background value.

Where possible, staff prefers that the recommended background concentrations come from nearby monitoring stations with similar characteristics. For this project the Mojave monitoring station (ozone, PM10, PM2.5, and NO_2 [prior to 2005]) is located reasonably close to the project site and should be fairly representative of the more rural nature of the project site; while the Lancaster (CO) monitoring station is located in a more populated area and is located much closer to the influence of the South Coast Air Basin, so this monitoring location should provide conservatively high background concentrations for the project site, and the Trona (2005-2007 NOx and SO_2) monitoring station while located in a more remote area has two very large nearby emission sources of NOx and SOx (Searles Valley Minerals and Ace Cogeneration Company) so this monitoring station location should also provide conservatively high background concentrations for the project site.

The background concentrations for PM10 are at or 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

The proposed project site is approximately 2,012 acres, which includes an approximately 1,244 acre solar thermal collection field using a parabolic trough mirror design. This project is proposed to be built on private lands; therefore, federal General Conformity (40 CFR Part 93 Subpart B) requirements do not apply to BSEP. The plant site is largely vacant and significantly disturbed from past agricultural activities that occurred up to the early 1980’s. Several abandoned structures currently exist in a small area east of SR-14 near the site access point from the highway. These structures are expected to be demolished in accordance with existing regulations.

The project would utilize two 30 million Btu/hr natural gas-fueled auxiliary boilers to reduce startup time and to keep the temperature of the heat transfer fluid (HTF) above its freezing point (54 °F). To provide fuel to these two boilers, a new 17.6-mile, eight-inch gas pipeline would be constructed to connect the Project to an existing Southern California Gas Company pipeline west of California City.

The proposed solar energy facility would use an 11 cell wet cooling tower for power plant cooling. Water will be supplied from onsite groundwater wells, and will be treated as necessary for cooling tower and other onsite uses. The cooling tower purge water will be piped to lined, onsite evaporation ponds that are sized to meet the solids generation for the life of the plant. However, if necessary for maintenance the dewatered pond, solids may be shipped offsite for disposal in an appropriate landfill.

The project would also have several other operating emission sources including: 1) six 6,000-gallon HTF expansion tanks vented to a vapor control system; 2) an HTF vapor control system with carbon adsorption units is series; 3) a diesel-fueled 300 horsepower firewater pump engine for fire protection; 4) a contaminated soil bio-remediation area; and 5) on-site mobile equipment needed for site maintenance (mirror washing) and operation.

The project also includes new electrical interconnection to transmission system of the Los Angeles Department of Water and Power (LADWP). The applicant has filed this electrical interconnection request for the LADWP, and is waiting for approval of the two options. The decision on which option to be built would be made once the Facilities Study is completed by the participating transmission system owner. The first of the two options is the construction of a new, approximately 3.5-mile 230kV transmission line (of which approximately 1.6 miles will be within the 2,012-acre plant site boundary), that would run west from the power black across SR-14 and south across private property to the Barren Ridge Switching Station. The second option is the construction of a new, approximately 2.3-mile 230kV transmission line (of which approximately 1.6 miles will be within the plant site boundary), that would run west across SR-14 to a new switching station to be constructed at the location where the Project's transmission line first meets LADWP's existing transmission right-of-way (ROW). A second, 230kV transmission line slightly over one mile long would then be constructed east of and adjacent to the existing LADWP ROW from the new switching station down to the Barren Ridge Station.

PROJECT CONSTRUCTION

Beacon Solar Energy Project solar power plant would be constructed for approximately 25 months. Construction of the natural gas supply pipeline and construction of transmission line would occur for five months and three months respectively, and all construction elements would occur concurrently. Construction emissions can be divided into two types; onsite emissions and offsite emissions. Onsite emissions results from site preparation and various construction activities using heavy-duty vehicles and equipment. Offsite emissions will occur from construction worker vehicles and material delivery trucks. The applicant's construction emission estimates are provided below in **Air Quality Tables 6** through **8**.

Air Quality Table 6
BSEP Construction - Maximum Daily Emissions [a]

Solar Facility Construction	Daily Emissions (lbs/day)					
	NOx	SOx	CO	VOC	PM10	PM2.5
Maximum Onsite Emissions	1037.3	0.9	714.4	119.3	215.7	102.9
Maximum Offsite Emissions	133.1	0.1	896.7	67.2	47.6	10.6
Maximum Total Emissions	1089.4	1.0	1312.7	138.3	227.4	106.1
Gas Line Construction						
Construction Equipment	459.9	0.4	200.8	57.4	87.4	40.3
Offsite Motor Vehicle	69.8	0.0	346.5	28.5	17.0	4.4
Maximum Total Emissions	529.7	0.4	547.3	85.9	104.4	44.7
Transmissions Line Construction						
Construction Equipment	26.8	0.0	9.5	7.2	1.1	1.1
Onsite Motor Vehicle	3.2	0.0	1.3	0.3	76.9	16.4
Offsite Motor Vehicle	37.3	0.0	32.2	1.5	3.4	1.7
Maximum Total Emissions	67.3	0.1	43	9.0	81.4	19.2
Substation Construction (Transmission Line Option 2 Only)						
Maximum Onsite Emissions	53.5	0.1	20.1	5.3	41.3	11.1
Maximum Offsite Emissions	2.9	0.0	52.4	3.9	1.3	0.3
Maximum Total Emissions	56.3	0.1	72.5	9.2	42.6	11.3

Source: BS 2008a, DB 2008d, BS 2008g
[a] - The maximum daily emissions do not always occur on the same day for each pollutant.

Air Quality Table 7
BSEP Construction - Maximum Monthly and Annual Emissions

Solar Facility Construction	Monthly Emissions (lbs/month)					
	NOx	SOx	CO	VOC	PM10	PM2.5
Maximum Onsite Emissions	22,821	21	15,717	2,625	4,746	2,264
Maximum Total Emissions	23,967	21	28,880	3,043	5,003	2,335
Solar Facility Construction	Annual Emissions (tpy)					
Maximum Onsite 12-Month Total	86.2	0.1	70.9	10.3	21.2	9.1
Maximum 12-Month Total	96.2	0.1	148.6	15	24.4	9.9

Source: BS 2008a, DB 2008d, BS 2008g

Air Quality Table 8
BSEP Construction - Total Emissions

Solar Facility Construction	Total Construction Emissions (tons)					
	NOx	SOx	CO	VOC	PM10	PM2.5
Onsite - Construction Equipment	93.19	0.09	105.84	12.19	4.76	4.25
Onsite - Motor Vehicle	0.72	0.00	1.19	0.14	0.02	0.02
Onsite - Asphaltic Paving	--	--	--	0.01	--	--
Onsite – Fugitive Dust	--	--	--	--	25.11	6.80
Onsite Subtotal	93.91	0.09	107.04	12.34	29.90	11.07
Offsite	18.27	0.01	132.21	10.03	7.03	1.40
Solar Facility Total	112.18	0.09	239.25	22.37	36.93	12.33
Gas Line Construction						
Construction Equipment	16.74	0.02	7.28	2.09	0.81	0.75
Fugitive Dust	--	--	--	--	3.59	0.94
Offsite Motor Vehicle	2.28	0.00	12.92	1.04	0.05	0.05
Gas Line Total	19.03	0.02	20.20	3.13	4.46	1.74
Transmissions Line Construction						
Construction Equipment	0.81	0.00	0.31	0.18	0.04	0.04
Onsite Motor Vehicle	0.06	0.00	0.03	0.01	0.00	0.00
Fugitive Dust	--	--	--	--	1.74	0.37
Offsite Motor Vehicle	0.66	0.00	0.77	0.04	0.02	0.02
Transmission Line Total	1.54	0.00	1.11	0.23	1.80	0.43
Substation Construction (Transmission Line Option 2 Only)						
Construction Equipment	4.39	0.00	1.90	0.59	0.23	0.21
Onsite Motor Vehicle	0.03	0.00	0.06	0.01	0.00	0.00
Fugitive Dust	--	--	--	--	3.78	0.80
Offsite Motor Vehicle	0.37	0.00	2.33	0.18	0.01	0.01
Substation Total	4.79	0.00	4.29	0.78	4.01	1.02
Total Construction Emissions	137.54	0.11	264.85	26.51	47.20	15.52

Source: BS 2008a, DB 2008d, BS 2008g

Staff's review of the applicant's emission estimate indicates that there is a potential that the fugitive dust emissions have been underestimated due to a low silt content estimate used to determine the unpaved road dust and dozing/scraping/grading emission factors. The geotechnical report indicates that soil samples taken at shallow depths (5 feet at higher) had silt contents ranging from 12-60%. The silt content assumption used in the applicant's fugitive dust calculations was 7.5%. Additionally, the dust suppression control for unpaved road travel used for twice daily watering (68% control) is identified as an SCAQMD approved value but it is not consistent with SCAQMD's currently documented water dust suppression control factor (55% control).

One aspect of the quantification of the construction emissions that were inadvertently not analyzed were the emissions associated with the delivery of the considerable amounts of materiel such as the mirrors, the HTF heat collection elements and support structures that will be delivered to the site. Considering the large scale of the project, there will be undoubtedly considerable, most likely semi- truck deliveries to the project site over approximately two year construction schedule. An accurate accounting of those emissions within Kern County needs to be considered and will be presented in the Final Staff Assessment.

PROJECT OPERATION

The BSEP facility would be a nominal 250 Megawatt (MW) parabolic solar trough thermal solar electrical generating facility (BSEP 2008a). The direct air pollutant emissions from power generation are negligible; however, there are required auxiliary equipment and maintenance activities necessary to operate and maintain the facility. The BSEP stationary and mobile emission sources are as follows:

- Two 30 MMBtu natural gas-fueled boilers used to maintain the temperature of the heat transfer fluid (HTF) above freezing during cold months and pre-warming for daily startup year-round;
- An 11 cell cooling tower with a high efficiency mist eliminator;
- Onsite diesel and gasoline fueled maintenance vehicles used for mirror washing and other maintenance/operation support activities.
- A 300-bhp diesel-fired emergency fire water pump engine;
- Six heat transfer fluid (HTF) expansion/ullage tanks with associated piping;
- An HTF system carbon adsorption based vapor emission control system;
- Spent HTF waste loadout; and
- A contaminated soil bio-remediation area.

The following assumptions were used to develop the hourly, daily, and annual emissions estimate for BSEP operation:

A. Maximum Hourly Emissions
  - Both boilers, the cooling tower, the emergency fire pump engine, and HTF vent all operate for the full hour.
  - There is one HTF waste loadout (using a truck) event.
  - The maximum hourly use of the mirror wash truck, maintenance vehicles, weed abatement vehicle, and soil stabilization vehicles that operate for 24, 384, 40 and 40 miles per day, respectively, is one fifth of the daily mileage estimate.

B. Maximum Daily Emissions
  - Both boilers operate for 14 hours per day.
  - The cooling tower operates for 16 hours per day.
  - The emergency fire pump engine operates for one hour per day.
  - The HTF vent operates for two hours per day.
  - There are two HTF waste loadout events per day.
  - The mirror wash truck, maintenance vehicles, weed abatement vehicle, and soil stabilization vehicles operate for 24, 384, 40 and 40 miles per day, respectively.

C. Maximum Annual Emissions
  - Both boilers operate for 1,000 hours per year.

- The cooling tower operates for 5,840 hours per year.
- The emergency fire pump engine operates for 200 hours per year.
- The HTF vent operates for 730 hours per year.
- There are 12 HTF waste loadout events per year.
- The mirror wash truck, maintenance vehicles, weed abatement vehicle, and soil stabilization vehicles operate for 3,000, 96,000, 340, and 340 miles per year, respectively.

The BSEP onsite stationary source and mobile equipment emissions, including fugitive PM10 emissions, are estimated and summarized in **Air Quality Table 9**.

Air Quality Table 9
BSEP Operation - Maximum Hourly, Maximum Daily, and Annual Emissions[a]

	Maximum Hourly Emissions (lbs/hr)					
Emission Source	NOx	SOx	CO	VOC	PM10	PM2.5
Boilers 1 and 2 (combined emissions)	0.66	0.03	2.22	0.31	0.43	0.43
Cooling Tower	0.00	0.00	0.00	0.00	0.60	0.60
Emergency Fire Pump Engine	1.85	0.00	1.72	0.10	0.10	0.10
HTF Expansion Tanks and Fugitive Emissions	0.00	0.00	0.00	1.63	0.00	0.00
HTF Vent	0.00	0.00	0.00	0.63	0.00	0.00
Bio-Remediation Operation	0.00	0.00	0.00	0.00	0.00	0.00
Waste Loadout	0.00	0.00	0.00	7.07	0.00	0.00
Maintenance Vehicles (all types)	0.62	0.00	0.42	0.06	5.19	1.12
Total Maximum Hourly Emissions	3.13	0.03	4.36	9.80	6.32	2.25
Source	Maximum Daily Emissions (lbs/day)					
Boilers 1 and 2 (combined emissions)	9.24	0.48	31.08	4.40	6.08	6.08
Cooling Tower	0.00	0.00	0.00	0.00	9.55	9.55
Emergency Fire Pump Engine	1.85	0.00	1.72	0.13	0.10	0.10
HTF Expansion Tanks and Fugitive Emissions	0.00	0.00	0.00	21.39	0.00	0.00
HTF Vent	0.00	0.00	0.00	1.25	0.00	0.00
Bio-Remediation Operation	0.00	0.00	0.00	0.10	0.00	0.00
Waste Loadout	0.00	0.00	0.00	14.15	0.00	0.00
Maintenance Vehicles (all types)	4.70	0.00	5.77	0.64	72.26	15.45
Total Maximum Daily Emissions	15.79	0.48	38.57	42.06	87.99	31.18
Source	Annual Emissions (tons/year)					
Boilers 1 and 2 (combined emissions)	0.33	0.02	1.11	0.16	0.22	0.22
Cooling Tower	0.00	0.00	0.00	0.00	1.74	1.74
Emergency Fire Pump Engine	0.19	0.00	0.17	0.01	0.01	0.01
HTF Expansion Tanks and Fugitive Emissions	0.00	0.00	0.00	3.90	0.00	0.00
HTF Vent	0.00	0.00	0.00	0.23	0.00	0.00
Bio-Remediation Operation	0.00	0.00	0.00	0.02	0.00	0.00
Waste Loadout	0.00	0.00	0.00	0.08	0.00	0.00
Maintenance Vehicles (all types)	1.94	0.00	0.61	0.15	7.54	1.65
Total Annual Emissions	2.46	0.02	1.89	4.55	9.51	3.62

Source: BS 2008a, KCAPCD 2009
[a] The District included estimates of the fugitive VOC emissions from the HTF tanks and piping components and bio-remediation operation that were not included in the AFC, while they did not include an evaluation of the waste loadout and maintenance vehicle emissions, which staff has taken from the applicant's emission estimate in the AFC.

During the operation phase of the project, the facility's annual emissions are primarily generated from the two 30 MMBtu natural gas-fueled boilers, the 11 cell cooling tower

(PM emissions), and the onsite maintenance vehicles. There are also occasionally high hourly or daily emissions and a small amount of annual emissions that result from the operation of the 300-bhp diesel-fired emergency fire water pump engine, the six heat transfer fluid (HTF) expansion/ullage tanks and piping system, and the HTF expansion tanks vapor control system, and spent HTF waste loadout.

The maximum daily boiler emissions are based on 14 hours per day per boiler, which is well above the expected average daily boiler use, which would be approximately two hours per day for pre-warming for daily startup and another 0.5 hours per day to 2.5 hours per day during cold months, October through February, for HTF freeze protection (DB 2008d). Freeze protection operation would be longer on extremely cold days, which is the basis for the maximum daily boiler use estimate.

Staff is concerned that the maintenance vehicle emissions required for the maintenance of this over 2,000 acre site could be underestimated, particularly the fugitive dust emissions, which like the construction emission estimates use emission factors that may not be properly calculated[3] or use assumptions that properly reflect conditions at the site. Additionally, staff is concerned that the onsite contaminated soil bio-remediation area emissions are not properly estimated considering the vehicle/equipment emissions required to move the contaminated soils to the bio-remediation area, to mix the soils and treatment mixtures, and to remove the treated soils.

INITIAL COMMISSIONING AND CLOSURE

Initial commissioning refers to a period prior to beginning commercial operation when the equipment undergoes initial tests. Because of this project's use of a non-fuel fired generating technology staff does not expect significant changes in emissions from the facility commissioning activities compared to that of full production.

Eventually the facility would close, either as a result of the end of its useful life or through some unexpected situation such as a natural disaster or catastrophic facility breakdown. When the facility closes, all sources of air emissions would cease to operate and thus all impacts associated with those emissions would no longer occur. The only other expected emissions would be equipment and vehicle emissions and fugitive particulate emissions from the dismantling activities. These activities would be of much a shorter duration than construction of the project and would create reduced impacts from those evaluated for construction. However, fugitive dust controls would be necessary during the dismantling activities to mitigate potential short-term impacts.

[3] The calculation of the operational unpaved fugitive dust emission factor appears to use the water-dust suppression controlled emission factor determined from construction (68% control) and then incorrectly uses another 80% control on top of the controlled construction emission factor to account for the use of a dust suppressant, which provides an overall control efficiency of 93.6%. Staff believes that the 80% control assumption should be used alone and would need to assume the use of a chemical dust suppressant rather than water dust control. Therefore staff believes that the maintenance vehicle fugitive dust emissions are under predicted by at least a factor of three on this basis alone; and there are also issues with the silt content assumed in the emission factor calculation.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assessed three kinds of primary and secondary[4] impacts: construction, operational, and cumulative. Construction impacts result from the emissions occurring during site preparation and construction of the project. Operational impacts result from the emissions of the proposed project during normal operation, which includes all of the onsite auxiliary equipment (boilers, cooling tower, fire pump engine, etc.) and the maintenance vehicle emissions. Cumulative impacts result from the proposed project's incremental effect, 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, and15355.)

METHOD AND THRESHOLDS FOR DETERMINING SIGNIFICANCE

Staff used two main significance criteria in evaluating this project. First, all project emissions of nonattainment criteria pollutants and their precursors (NOx, VOC, PM10 and SO_2) are considered significant cumulative impacts that must be mitigated. Second, any AAQS violation or any contribution to any AAQS violation caused by any project emissions is considered to be significant and must be mitigated. 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, when analyzing renewable projects with very low direct criteria pollutant emissions from stationary sources associated with electric generation located in areas with generally good air quality that are non-attainment of ambient air quality standards primarily or solely due to pollutant transport, the mitigation that is considered is limited to feasible emission controls. These feasible emission controls are applied to both the stationary sources (such as BACT) and the on-site non-stationary emission sources (such as maintenance vehicles) including associated fugitive dust emission sources.

The ambient air quality standards that staff uses as a basis for determining project significance are health-based standards established by the ARB and U.S. EPA. They are set at levels 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, including a margin of safety.

DIRECT/CUMULATIVE 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 would be significantly diluted by the time they reach ground

[4] 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.

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 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 has used the EPA-approved ARMS/EPA Regulatory Model (AERMOD version 07026) air dispersion model to estimate the direct impacts of the project's NOx, PM10, CO, and SOx emissions resulting from project construction and operation.

Staff revised the background concentrations provided by the applicants, replacing them with the available highest ambient background concentrations as show in **Air Quality Table 5**. Staff added the modeled impacts to these background concentrations, then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or would contribute to an existing violation.

The inputs for the air dispersion models include stack information (exhaust flow rate, temperature, and stack dimensions), specific boiler emission data and meteorological data, such as wind speed, 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 Mojave Poole Street meteorological site during 2002 through 2004, which is the closest complete meteorological data source to the project site, and supplemented to fill missing data using the Lancaster William J. Fox Field Meteorological site. Concurrent upper air data from the Mercury Desert Rock Airport in Mercury, Nevada was also used. This meteorological data was approved for use by the KCAPCD. Additionally, the applicant obtained hourly ozone and NO_2 ambient data from the Mojave Poole Street monitoring station for 2002 to 2004 that was used in a more refined NO_2 impact modeling analysis using the Ozone Limiting Method (OLM) option that is available with AERMOD.

Construction Impacts and Mitigation

The following section discusses the project's short-term direct and cumulative construction ambient air quality impacts, as estimated by the applicant, and provides a discussion of appropriate mitigation.

Construction Impact Analysis

The applicant used the EPA guideline ARMS/EPA Regulatory Model (AERMOD) model to estimate ambient impacts. The emission sources for the construction 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 added to the exhaust emissions for PM modeling. These two sources were modeled as rectangular 15 acre area sources, approximately 550 meters east-west and 110 meters north-south, near the center of the 2,000 acre site. The equipment area source was set at an initial release height of 3.7 meters and with an initial vertical dimension of 6.88 meters. The vehicle area source was set at an initial release height of 2.0 meters and with an initial vertical dimension of 2.13 meters.

Staff has reviewed the construction emissions air dispersion modeling procedures and has several concerns. First, the emissions were modeled as two overlaying 15 acre area sources quite some distance from the property fence line, while the project footprint covers much of the 2,000 acre site. Second, some of the emission inputs do not seem to match the maximum onsite emissions data provided by the applicant, such as the modeled NOx emissions that appear to be about 10% too low. Third, the initial release parameters, while reasonable for thermally buoyant engine exhausts, are likely too high for the fugitive dust sources for the PM10/PM2.5 modeling. Fourth, the use of small area sources concentrates the emissions, which may actually cause reduced dispersion to be estimated. Staff will review the modeling further and may perform a revised analysis for the Final Staff Assessment.

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 or gas turbines, 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 emission with the available ambient ozone. The NOx OLM method used assumed an initial NO_2/NOx ratio of 0.1 for diesel equipment. Actual monitored hourly background ozone concentration data (2002 to 2004 Mojave Poole Street monitoring station data that corresponds with the meteorological files) were used by this modeling method to calculate maximum potential NO to NO_2 conversion to determine the maximum hourly NO_2 impacts.

Using estimated peak hourly, daily and annual construction equipment exhaust emissions, the applicant modeled construction emissions to determine impacts. To determine the construction impacts on ambient standards (i.e. 1-hour through annual) the on-site construction emission levels were modeled assuming that the emissions would occur during a daily construction schedule of 8 am to 4 pm. The predicted on-site emissions concentration levels were added to a conservatively estimated background of existing emission concentration levels to determine the cumulative effect. The results of the applicant's modeling analysis are presented in **Air Quality Table 10**. The construction modeling analysis includes both the onsite fugitive dust and vehicle exhaust emissions.

Air Quality Table 10
Maximum Project Construction Impacts

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background [1] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr	216.7	103.6	320.3	339	94%
	Annual	1.1	9.5	10.6	57	19%
PM10	24-hr	36.9	73	109.9	50	220%
	Annual	0.29	19.5	19.8	20	99%
PM2.5	24-hr	15.2	17.8	33.0	35	94%
	Annual	0.13	6.2	6.3	12	53%
CO	1-hr	1,371	3,680	5,051	23,000	22%
	8-hr	173.8	1,778	1,952	10,000	20%
SO_2	1-hr	1.6	86.5	88.1	665	13%
	3-hr	0.54	77.8	78.3	1300	6%
	24-hr	0.07	13.1	13.2	105	13%
	Annual	0.001	2.7	320.3	80	3%

Source: BSEP 2008a, BSEP 2008b.
Note
1. Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.

Staff's review of the applicant's modeling analysis found that the construction emissions were not well placed geographically within or around the site. This was particularly true for the annual modeling runs where all of the emissions were placed in a single 15 acre area near the center of the 2,000 acre site, which was not even centered around the main site facilities. Staff has completed a revised modeling analysis for NO_2 and PM10/PM2.5 impacts that increases the area of emissions and better places the majority of the emissions over the sites main construction areas. The applicant's impact analysis along with a review of the emission estimates indicate that there is no potential for significant CO or SO_2 impacts with or without the on-site maintenance vehicle emissions, so they were not remodeled. The results of staff's modeling analysis are presented in **Air Quality Table 11.**

Air Quality Table 11
Project Construction Emission Impacts – Staff's Modeling Analysis

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background [a] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr [b]	228.3	103.6	331.9	339	98%
	Annual [c]	2.0	9.5	11.5	57	20%
PM10	24-hr	74.2	73	147.2	50	294%
	Annual	0.76	19.5	20.3	20	101%
PM2.5	24-hr	4.40	17.8	22.2	35	63%
	Annual	0.20	6.2	6.4	12	53%

Source: Staff Analysis.
Notes:
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.
[b] The 1-hour NO_2 maximum was determined using NOx_OLM modeling and comparison of actual hourly NO_2 background with the modeled NO_2 impacts.
[c] The annual NO_2 results were corrected based on the U.S.EPA default ambient ratio method of 0.75 (NO_2/NOx).

Staff's modeling results indicate the potential for higher localized impacts from the construction activities than determined by the applicant. In particular there is a potential for elevated PM10 and NO_2 levels near the project fence line, including the potential for NO_2 impacts very close to the state 1-hour standard and further exacerbation of existing violations of the state PM10 standards. Staff notes that the maximum local background 24-hour measurements of PM10 may be significantly impacted by wind-blown dust. However, in light of the existing PM10 and ozone non-attainment status for the project site area, staff considers the construction NOx, VOC, and PM emissions to be potentially significant and, therefore, staff is recommending that the off-road equipment and fugitive dust emissions be mitigated to the extent feasible.

Construction Mitigation

Staff recommends that construction emission impacts be mitigated to the greatest feasible extent including all required measures from the District's rules and regulations, as well as, other measures considered necessary by staff to fully mitigate the construction emissions.

Applicant's Proposed Mitigation

To mitigate the impacts due to construction of the facility the applicant has proposed, or stipulated to, nearly identical conditions of certification as staff mitigation measures **AQ-SC1** through **AQ-SC5**, as discussed below under staff proposed mitigation (BSEP 2008a). However, the versions of those measures, particularly **AQ-SC5** are somewhat dated versions of these staff conditions.

Adequacy of Proposed Mitigation

The applicant has essentially stipulated to previous versions of staff's construction air quality mitigation conditions, so this stipulation is generally considered adequate with minor modifications to incorporate the latest staff recommendations and site specific concerns.

Staff Proposed Mitigation

Staff recommends construction PM10 and NOx emission mitigation measures as articulated in Conditions of Certification **AQ-SC1** through **AQ-SC5** that include modified versions of similar conditions proposed by the applicant in the AFC. In particular, the there are slight modifications to the fugitive dust controls necessary to control the higher fugitive dust emission potential for this type of project, and modifications to the off-road equipment mitigation measure to update it to both current staff standards and again in consideration of the high unmitigated emission potential for the construction of this project.

Staff recommends **AQ-SC1** to require the applicant to have an on-site construction mitigation manager who would 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**. Recommended Condition of Certification **AQ-SC3** formalizes the fugitive dust control requirements. Recommended Condition of

Certification **AQ-SC4** would limit the potential offsite impacts from visible dust emissions, to respond to situations when the control measures required by **AQ-SC3** are not working effectively to control fugitive dust from leaving the construction site area.

Staff recommends Condition of Certification **AQ-SC5** to mitigate the PM and NOx emissions from the large diesel-fueled construction equipment. Implementation of this mitigation measure would provide additional primary and secondary PM mitigation to supplement the recommended fugitive dust mitigation measures. This condition requires the use of EPA/ARB Tier 2 engine compliant equipment for equipment over 100 horsepower where available, a good faith effort to find and use available EPA/ARB Tier 3 engine compliant equipment over 100 horsepower, and also includes equipment idle time restrictions and engine maintenance provisions. The Tier 2 standards include engine emission standards for NOx plus non-methane hydrocarbons, CO, and PM emissions; while the Tier 3 standards further reduce the NOx plus non-methane hydrocarbons emissions. The Tier 2 and Tier 3 standards became effective for engine/equipment model years 2001 to 2003 and models years 2006 to 2007, respectively, for engines between 100 and 750 horsepower.

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 would be less than significant with the implementation of the mitigation measures contained in the recommended Conditions of Certification.

Operational Impacts and Mitigation

The following section discusses the project's direct and cumulative 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 has provided a modeling analysis using the EPA-approved AERMOD model to estimate the impacts of the project's non-vehicular NOx, PM10, CO, and SOx emissions resulting from project operation (BSEP 2008a). Similar to the assessment of construction impacts, staff added the modeled impacts to the available highest ambient background concentrations recorded during the previous three years from nearby monitoring stations to assess the project's operational impacts.

Staff tabulated the modeling analysis in **Air Quality Table 12**. The data show that the project's stationary sources do not cause any new violations of NO_2, PM2.5, CO or SO_2 air quality standards, even using the worst case ambient concentrations recorded.

Air Quality Table 12
Project Operation Emission Impacts – Applicant's Modeling Analysis

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background [a] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr	79.7	103.6	183.3	339	54%
	Annual	0.01	9.5	9.5	57	17%
PM10	24-hr	0.44	73	73.4	50	147%
	Annual	0.04	19.5	19.5	20	98%
PM2.5	24-hr	0.44	17.8	18.2	35	52%
	Annual	0.04	6.2	6.2	12	52%
CO	1-hr	75.4	3,680	3,755	23,000	16%
	8-hr	16.3	1,778	1,794	10,000	18%
SO_2	1-hr	0.16	86.5	86.7	665	13%
	3-hr	0.08	77.8	77.9	1300	6%
	24-hr	0.01	13.1	13.1	105	12%
	Annual	0.0002	2.7	2.7	80	3%

Source: BSEP 2008a, BSEP 2008b.
Note:
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.

The applicant did not model the operational, on-site vehicle emissions, including their associated fugitive dust emission. The applicant has indicated that the project would create a PM emission reduction in comparison with current conditions due to their unspecified fugitive dust control plan being better than the current site conditions; however, they have not provided any comparisons in estimated dust emissions to back up this assertion. Staff has completed a revised modeling analysis for NO_2 and PM10/PM2.5 impacts that includes the on-site maintenance vehicle tailpipe and fugitive dust emissions. The applicant's impact analysis along with a review of the emission estimates indicate that there is no potential for significant CO or SO_2 impacts with or without the on-site maintenance vehicle emissions, so they were not remodeled. The results of staff's modeling analysis are presented in **Air Quality Table 13.**

Air Quality Table 13
Project Operation Emission Impacts – Staff's Modeling Analysis

Pollutants	Avg. Period	Impacts ($\mu g/m^3$)	Background [a] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hr	102.5	103.6	206.1	339	61%
	Annual	0.24	9.5	9.7	57	17%
PM10	24-hr	26.3	73	99.3	50	199%
	Annual	0.9	19.5	20.4	20	102%
PM2.5	24-hr	3.7	17.8	21.5	35	61%
	Annual	0.22	6.2	6.4	12	53%

Source: Staff Analysis.
Note:
[a] Background values have been adjusted per staff recommended background concentrations shown in **Air Quality Table 5**.

Staff's modeling analysis indicates higher short-term and long-term impacts than estimated by the applicant. However, the results of both modeling analyses indicate that the project's stationary source operational impacts would not create violations of NO_2, PM2.5, SO_2, or CO standards, but could further exacerbate violations of the PM10 standards. In light of the existing PM10 and ozone non-attainment status for the project site area, staff considers the potential operating emissions to be potentially significant and, therefore, staff is recommending the emissions from both the stationary and maintenance activities be mitigated using feasible emission control measures.

Chemically Reactive Pollutant Impacts

The project will have direct emissions of chemically reactive pollutants (NOx, SOx, and VOC), but will also have indirect emission reductions associated with the reduction of fossil-fuel fired power plant emissions due to the project displacing the need for their operation. The exact nature and location of such reductions is not known; however, it is not unreasonable to assume that some of those reductions will occur in upwind areas such as the South Coast Air Basin since the electricity supplied by this project will be directed to LADWP transmission lines. However, the overall magnitude and downwind impact of those upwind emission reductions is speculative and staff's impact analysis has not considered these potential reductions as an offset source for the project's emissions, so the discussion below focuses on the direct emissions from the project within Kern County.

Ozone 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.

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 BSEP 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.

PM2.5 Impacts

Secondary particulate formation, which is assumed to be 100% 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 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 would not necessarily lead to increases in ambient PM2.5 concentrations. In the case of an ammonia poor environment, there is insufficient ammonia to establish a balance and thus additional ammonia would tend to increase PM2.5 concentrations.

The eastern Kern County portion of the Mojave Desert Air Basin has not undergone the rigorous secondary particulate studies that have been performed in other areas of California, such as the San Joaquin Valley, that have more serious fine particulate pollution problems. However, the available chemical characterization data shows that the annual ammonium nitrate and ammonium sulfate fine particulate concentrations in Lancaster from 1994 to 2001 were approximately 25% of the state annual ambient PM2.5 standard (ARB 2005). 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 BSEP do have the potential (if left unmitigated) to contribute to higher PM2.5 levels in the region; however, the region is in attainment with PM2.5 standards and the low level of NOx and SOx emissions from this project would not significantly impact that status.

Impact Summary

The applicant is proposing to mitigate the project's stationary source NOx, VOC, SO_2, and PM10/PM2.5 emissions through the use of BACT. Additionally, staff recommends additional mitigation, specified in conditions of certification **AQ-SC6** and **AQ-SC7,** to reduce maintenance vehicle emissions, both tailpipe emission and fugitive dust emissions that could contribute to further ozone and PM10 violations.

In assessing the impacts of the two boilers, staff has analyzed when the units would operate on a routine basis and compare those impacts to ambient air quality conditions. Ozone violations typically occur between May and September. During that period, it would be expected that the boilers would be used to provide start-up steam demand approximately two hours a day with NOx emissions of approximately 1.3 lbs/day and VOC emissions of about 0.6 lbs/day (DB 2008d). This level of emissions do not constitute a significant contribution to ozone formation. For PM10, although there may be some days during spring, summer and fall when the background levels of PM10 may exceed the standards, the very low emissions of approximately 0.6 lb/day would not contribute in a significant manner to those violations.

During the winter months, the boilers would be operated slightly more, about 2.5 hours more per day on average and as much as 14 hours per day to provide heat for the anti-freeze system for the heat transfer fluid (DB 2008d and BS2008a). During the winter, there are no violations of the ambient ozone standards, and thus the boilers NOx and VOC emissions would not contribute to any violations of the ozone standards. Even though very occasionally there are PM10 violations during the winter, the low level of emissions of PM10 (approximately 0.75 lb/day on average and 4.2 lbs/day maximum) would not contribute to a significantly to any PM10 violations. With the applicant proposed and staff recommended emission mitigation, it is staff's belief that the project would not cause significant secondary pollutant impacts.

Operations Mitigation

Applicant's Proposed Mitigation

Emission Controls

As discussed in the air quality section of the AFC (BSEP 2008a), the applicant proposes the following emission controls on the stationary equipment associated with the BSEP operation:

Boilers

The applicant's proposed Best Available Control Technology (BACT) for the two 30 MMBtu/hr boilers would include ultra-low NOx burners (for NOx), good combustion practices (for CO), and operate exclusively on pipeline quality natural gas (for VOC, PM and SOx) to limit boiler emission levels. The AFC (BSEP 2008a) and FDOC conditions (KCAPCD 2009) provides the following BACT emission limits, each for the two boilers:

- NOx: 9.0 ppmvd at 3% O_2 (one-hour average)
- CO: 50 ppmvd at 3% O_2 (one-hour average)
- VOC: No specific concentration or emission limit
- PM10: No specific concentration or emission limit
- SO_2: No specific concentration or emission limit

Fire Water Pump Engine

The applicant's proposed Best Available Control Technology (BACT) for the fire pump engine is compliance with the New Source Performance Standards, Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, specifically an NSPS compliant engine. To meet this requirement the applicant is proposing a CARB/EPA Tier 3 engine with the following emission limits:

- NOx: 3.0 grams per break horsepower (including non-methane hydrocarbons - NMHC)
- CO: 2.6 grams per break horsepower
- VOC: (see NOx above)
- PM10: 0.15 grams per break horsepower
- SO_2: 15 ppm sulfur content fuel

Cooling Tower

The applicant's proposed Best Available Control Technology (BACT) for the cooling tower is the use of a high efficiency mist eliminator with a guaranteed drift efficiency of 0.0005%.

HTF Expansion Tank Emissions

The applicant’s proposed Best Available Control Technology (BACT) for the HTF Expansion Tank Emissions is a carbon adsorption unit with two carbon beds in series that will control VOC emissions by 99%.

Waste Loadout

The applicant has not proposed any specific emission controls for this minor emission source.

Contaminated Soils Bioremediation Area

The applicant has not proposed any specific emission controls for this minor emission source.

Maintenance Vehicles

The applicant has not proposed any specific emission controls for this emission source.

Emission Offsets

The applicant has not proposed any emission offsets and the stationary source emissions for BSEP would be well below District offset thresholds.

Adequacy of Proposed Mitigation

Staff concurs with the District’s determination that the project’s stationary source 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. However, staff believes that the BSEP maintenance vehicle emissions should be mitigated to the maximum extent feasible through the use of electric engines, or alternative fueled engines, or clean engine technology.

Staff Proposed Mitigation

As mentioned earlier in the discussions of the ozone and PM10 impacts, staff believes that the project’s direct stationary source ozone precursors and PM10 emissions are minimal, but along with the maintenance vehicles emissions would likely be significant. Additionally, staff believes a solar renewable project, which would have a 30 to 40-year life in a setting likely to continue to be impacted by both local and upwind emission sources, should address its contribution to potentially ongoing non-attainment status of the PM10 and ozone standards. Therefore, staff recommends the following additional mitigation measures:

- Use of gasoline fueled light trucks as water tenders for parabolic mirror cleaning, or electric [battery] powered or alternative fuel vehicles, with a similar or lower emission profile of gasoline fueled light trucks, thereby reducing the ozone precursor emissions and fugitive dust emissions from mirror cleaning operations to the extent feasible;
- Use of electric [battery] powered vehicles, similar to those use in the golf course, to transport maintenance crew within the facility, thereby eliminating knobby, off-road

tires that could disturb stabilized soil and roads and eliminating almost all the ozone precursor emissions during operation;

- Wind erosion control techniques such as windbreaks, water, and chemical dust suppressants, should be used on areas that could be disturbed by vehicles or wind. Any windbreaks used would remain in place until the soil or road is stabilized: and
- Limit vehicle speeds within the facility to no more than five miles per hour to address fugitive PM emissions from the site.

Staff recommendations for maintenance vehicles and ongoing fugitive dust control are specified in conditions of certification **AQ-SC6** and **AQ-SC7**, respectively.
Staff is proposing Condition of Certification **AQ-SC8** to ensure that the license is amended as necessary to incorporate changes to the air quality permits.

Staff has determined that the proposed emission controls and emission levels, along with the applicant proposed and staff recommended emission offset package, would mitigate all project air quality impacts to less than significant.

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.

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 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.

Much of the preceding discussion is concerned with cumulative impacts. The "Existing Ambient Air Quality" subsection describes the air quality background in the Kern County portion of the Mojave Desert Air Basin, including a discussion of historical 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" subsection discusses the project's contribution to the local existing background caused by project operation. The following subsection includes two 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 project's *localized cumulative impacts*, the project's direct operating emissions combined with other local major emission sources;

Summary of Projections

The eastern Kern County portion of the MDAB is designated as non-attainment for both federal (8-hour) and State (1-hour) ozone and state PM10 standards. All other criteria pollutants (NO_2, and SO_2, and PM2.5) are considered to be in attainment by the State, and in attainment and/or unclassified under federal standards.

The KCAPCD developed an ozone redesignation request and maintenance plan for the federal 1-hour ozone standard in 2003 (KCAPCD 2003). The eastern portion of Kern County was determined to be in attainment of the 1-hour ozone standard by the USEPA in 2004 and deemed a maintenance area (FR 2004). The District is in the process for being reclassified for the 8-hour ozone standard, so any initial 8-hour ozone standard attainment plan is not due to USEPA until sometime in 2009; however, the 1-hour ozone maintenance plan remains in force until such time as the 8-hour attainment plan is approved. The 1-hour ozone maintenance plan requires no new control measures for maintaining attainment of the 1-hour standard.

The KCAPCD California Clean Air Act Ozone Air Quality Attainment Plan was approved by the California Air Resources Board (CARB) on February 18, 1993. KCAPCD's most recent Annual Implementation Progress Report for this attainment plan was completed in 2005 (KCAPCD 2005), and will likely be updated at the same time as the initial federal 8-hour ozone attainment plan is due in 2009. The implementation progress report notes that the area is overwhelmingly impacted by upwind transport, with the majority of the ambient ozone pollution in the area being due to pollutants that are transported by the wind from the San Joaquin Valley and South Coast Air Basins. The implementation progress report indicates that no additional control measures are required for attainment of the ozone CAAQS, attainment will occur by reducing the pollution in these adjacent air basins.

Therefore, both the federal and State ozone management plans require no new control measures that would affect the proposed Project and compliance with existing KCAPCD rules and regulations during construction and operation would ensure conformance with the approved KCAPCD air quality management plans.

Summary of Conformance with Applicable Air Quality Plans

The applicable air quality plans do not outline any new control measures applicable to the proposed project's operating emission sources. Therefore, compliance with existing District rules and regulations would ensure compliance with those air quality plans.

Localized Cumulative Impacts

Since the power plant air quality impacts can be reasonably estimated through air dispersion modeling (see the “Operational Modeling Analysis” subsection) the project 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 “Environmental Setting” 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 six miles of the project site. Based on staff’s modeling experience, beyond six 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 six 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 two 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 the BSEP if the high impact area is the result of high fence line concentrations from another stationary source and BSEP 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 project alone (see the “Operational 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 project emissions can be evaluated, and the mitigation itself can be proposed by staff and/or the applicant (see the “Mitigation” subsection).

The applicant, in consultation with Kern County Planning Department and the District, has conducted a survey of new development projects and stationary sources that have potential for emissions of criteria air contaminants within six miles of the project site that are either under construction, or have received permits to be built or operate in the foreseeable future. The survey results indicate that no such stationary sources exist within the six miles radius[5] of the proposed project site. Two non-stationary projects, the Los Angeles Department of Water and Power (LADWP) Pine Tree Wind Development Project and the LADWP Barren Ridge-Castaic Transmission Project, are located within six miles of the project site. These two projects would have temporary construction emissions and limited operating emissions consisting of inspection and maintenance operations.

The Pine Tree Wind Development Project, which is located approximately six miles west of the site in rugged topography, is currently under construction and scheduled to be in service in July 2009. Therefore, its construction would not significantly overlap the construction of the BSEP. Additionally, the maintenance emissions are not considered to be of a magnitude, given they would occur six miles from the BSEP site, to affect the modeling analysis on a cumulative basis.

The Barren Ridge-Castaic project, which has not yet completed its environmental review and licensing/permitting process, may or may not have construction activities that overlap the BSEP construction. However, those construction activities as a long linear project will be limited in duration and scope near the project site, and the operating inspection/maintenance emissions near the project site would be minimal. Therefore, this project’s emissions are not considered to be of a magnitude or duration to affect the modeling analysis on a cumulative basis.

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

[5] Staff assumes that impacts from projects beyond six miles would not affect the modeling analysis on a cumulative basis.

COMPLIANCE WITH LORS

The Kern County Air Pollution Control District issued a Preliminary Determination of Compliance (PDOC) for the BSEP on December 23, 2008 (KCAPCD 2008) and a Final Determination of Compliance (FDOC) on March 5, 2009 (KCAPCD 2009). Compliance with all District rules and regulations was demonstrated to the District's satisfaction in the DOC. The District's FDOC conditions are presented in the Conditions of Certification (**AQ-1** to **AQ-79**).

Energy Commission staff provided comments on the PDOC to the District on January 20, 2009 (CEC 2009). Staff has found that the revisions made to the FDOC adequately address staff's comments.

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 Standard (Subpart IIII). Additionally, this project would not require a PSD permit from U.S. EPA prior to initiating construction.

STATE

The applicant would demonstrate that the project would 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 Final Determination of Compliance and the Energy Commission's affirmative finding for the project. In the FDOC, the District concluded that the project should comply with this requirement as the screening health risk assessment they performed found risks to be below a Prioritization Score of 1.0, or below the need for any additional analysis or action.

The fire pump engine is also subject to the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines. This measure limits the types of fuels allowed, established maximum emission rates, establishes recordkeeping requirements. The proposed Tier 3 engine meets the emission limit requirements of this rule. This measure would also limit the engine's testing and maintenance operation to 50 hours per year.

LOCAL

The District rules and regulations specify the emissions control and offset requirements for new sources such as the BSEP. Best Available Control Technology would be implemented, and emission reduction credits (ERCs) are not required to offset the project's emissions by District rules and regulations based on the permitted stationary source emission levels for this project. Compliance with the District's new source requirements would ensure that the project would be consistent with the strategies and future emissions anticipated under the District's air quality attainment and maintenance plans.

The applicant provided an air quality permit application to the KCAPCD in April 2008 and the District issued a PDOC (KCAPCD 2008) on December 23, 2008 and on FDOC (KCAPCD 2009) on March 5, 2009. The FDOC 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 would comply with the District's applicable rules and regulations, as described below.

Regulation II – Permits

Rule 210.1 – New and Modified Stationary Source Review

This rule establishes the stationary source[6] requirements that must be met to obtain a PTO, including the requirement to comply with best available control technology (BACT), provide emission offsets for emission increase above specified thresholds; and provide a dispersion modeling analysis, an alternatives analysis, and a compliance certification (if applicable). In the FDOC, the District has determined that the proposed controls for the boilers, cooling tower, tank vent system, and firewater pump engine meet BACT requirements. The District has also determined that an inspection and maintenance program limiting VOC leaks on the HTF Piping Network component to less than 100 ppm would be BACT.

The BSEP, as a minor stationary source, does not require offsets, require a dispersion modeling, analysis, or require a compliance certification per District Rule 210.1.

Regulation IV – Prohibitions

Rule 401 - Visible Emissions

This rule limits visible emissions from emissions sources, including stationary source exhausts and fugitive dust emission sources. In the FDOC, the District has determined that the facility is expected to comply with this rule.

Rule 402 - Fugitive Dust

This rule limits fugitive emissions from certain bulk storage, earthmoving, construction and demolition, and manmade conditions resulting in wind erosion. With the implementation of recommended staff condition **AQ-SC7** the facility is expected to comply with this rule.

Rule 404.1 - Particulate Matter Concentration

The rule limits particulate matter (PM) emissions to less than 0.1 grains per standard cubic foot of gas at standard conditions. In the FDOC, the District has determined that the applicable equipment's (boiler, fire pump engine, cooling tower) PM emission concentration are less than 0.001 gr/scf and so will be well below the limits established by this rule.

Rule 407 - Sulfur Compounds

This rule limits discharge into the atmosphere of sulfur compounds exceeding 0.2% by volume concentration calculated as SO_2. In the FDOC, the District has determined that the use of pipeline quality natural gas and California diesel fuel in the boilers and fire pump engine, respectively, will ensure compliance with this rule.

[6] The maintenance vehicles are not stationary sources and are not subject to District rules.

Rule 409 - Fuel Burning Equipment - Combustion Contaminants

This rule limits discharge into the atmosphere from fuel burning equipment combustion contaminants exceeding in concentration at the point of discharge, 0.1 grain per cubic foot of gas calculated to 12% of carbon dioxide (CO_2) at standard conditions. In the FDOC, the District has determined that the applicable equipment's (boiler and fire pump engine) PM emission concentration are less than 0.001 gr/scf and so will be well below the limits established by this rule.

Rule 411 – Storage of Organic Liquids

This rule sets standards for storage of organic liquids with a true vapor pressure of 1.5 pounds per square inch or greater. The HTF storage/expansion tanks will be equipped with a vapor control system; therefore, the requirements of this rule do not apply.

Rule 414.2 – Soil Decontamination

This rule sets requirements for the VOC emissions from the handling and decontamination activities of VOC contaminated soils. In the FDOC, the District has determined that the on-site bio-remediation area will comply with "Maximum Allowable Addition Rates of Contaminated Soil" (Section V.B) and "Treatment System" (Section V.C) requirements of this rule, and that the applicant is proposing a "Land Farming" operation using bio-remediation to comply with BACT and the requirements of this rule.

Rule 419 – Nuisance

This rule restricts emissions that would cause nuisance or injury to people or property (identical to California Health and Safety Code 41700). In the FDOC, the District has determined that, due to control devices and inspection and maintenance requirements contained in the District conditions, compliance with this rule was expected.

Rule 422 - New Source Performance Standards

This rule incorporates the Federal NSPS (40 CFR 60) rules by reference. The proposed Tier 3 engine meets the emission limit requirements of the only NSPS ((Subpart IIII) that applies to the proposed BSEP equipment.

Rule 425.2 - Boilers, Steam Generators and Process Boilers (Oxides of Nitrogen)

This rule limits NOx emissions from boilers, steam generators, and process heaters to levels consistent with Reasonably Available Control Technology (RACT). The projects proposed boiler BACT emission controls provide emission levels in compliance with this Rule's RACT requirements.

Rule 429.1 - Cooling Towers (Hexavalent Chromium)

This rule prohibits the use of hexavalent chromium-bearing compounds in cooling towers. Enforcement of District Condition **AQ-14** will ensure compliance with this regulation.

NOTEWORTHY PUBLIC BENEFITS

Renewable energy facilities, such as the BSEP, are needed to meet California's mandated renewable energy goals that will also reduce system wide criteria pollutant emissions from power generation.

CONCLUSIONS

Staff has made the following preliminary conclusions about the BSEP:

- The project would comply with applicable District Rules and Regulations, including New Source Review requirements, and staff recommends the inclusion of the Districts FDOC conditions as Conditions of Certification **AQ-1** through **AQ-79**.
- The project's construction activities would likely contribution to significant adverse PM10 and ozone impacts. Staff recommends **AQ-SC1** to **AQ-SC5** to mitigate the potential impacts.
- The project's operation would not cause new violations of any NO_2, SO_2, PM2.5 or CO ambient air quality standards, and therefore, the project direct operational NOx, SOx, PM2.5 and CO emission impacts are not significant.
- The project's direct and indirect, or secondary emissions contribution to existing violations of the ozone and PM10 ambient air quality standards are likely significant. Therefore, staff recommends the use of gasoline-fueled light trucks, or electric or alternative fuel vehicles, to pull the water tanks (for washing of the parabolic mirrors), the use of electric-powered personnel vehicles, soil stabilizers for the mirror areas and roads, and on-site speed limits (**AQ-SC6** and **AQ-SC7**) to ensure that the potential ozone and PM10 impacts are mitigated to less than significant over the life of the project.
- The project would be consistent with the requirements of SB 1368 and the Emission Performance Standard for greenhouse gases (see **Appendix Air-1**).

PROPOSED CONDITIONS OF CERTIFICATION

STAFF CONDITIONS OF CERTIFICATION

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 60 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, AQ-SC5** and **AQ-SC6**.

Verification: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The District will notify the project owner of any necessary modifications to the plan within 30 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 following mitigation measures for the purposes of preventing all fugitive dust plumes from leaving the project. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

A. All unpaved roads and disturbed areas in the project and linear construction sites shall be watered as frequently as necessary 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.

B. No vehicle shall exceed 10 miles per hour within the construction site.

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

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

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

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

G. 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 District.

H. Construction areas adjacent to any paved roadway shall be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent run-off to roadways.

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

J. 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 at least twice daily (or 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.

K. 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.

L. 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.

M. 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.

Verification: 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 District and 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 (1) off the project site or (2) 200 feet beyond the centerline of the construction of linear facilities or (3) within 100 feet upwind of any regularly occupied structures not owned by the project owner 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 District 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 District before that time.

Verification: 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 and 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 Engines Control: The AQCMM shall submit to the CPM, in the MCR, a construction mitigation report that demonstrates compliance with the following mitigation measures for the purposes of controlling diesel construction-related emissions. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

A. All diesel-fueled engines used in the construction of the facility shall be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur.

B. 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.

C. A good faith effort shall be made to find and use off-road construction diesel equipment that has a rating of 100 hp to 750 hp and that meets the Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines as specified in Title 13, California Code of Regulations section 2423(b)(1). This good faith effort shall be documented with signed written correspondence by the appropriate construction contractors along with documented correspondence with at least two construction equipment rental firms.

D. All construction diesel engines, which have a rating of 50 hp or more, shall meet, at a minimum, the Tier 2 California Emission Standards for Off-Road Compression-Ignition Engines as specified in Title 13, California

Code of Regulations section 2423(b)(1). The following exceptions for specific construction equipment items may be made on a case-by-case basis.

1. Equipment with non-Tier 2 engines that have tailpipe retrofit controls that reduce exhaust emissions of NOx and PM to no more than Tier 2 levels.

2. Tier 1 equipment will be allowed on a case-by-case basis only when the project owner has documented that no Tier 2 equipment or emissions equivalent retrofit equipment is available for a particular equipment type that must be used to complete the project's construction. This shall be documented with signed written correspondence by the appropriate construction contractors along with documented correspondence with at least two construction equipment rental firms.

3. The construction equipment item is intended to be on site for five days or less.

4. Equipment owned by specialty subcontractors may be granted an exemption, for single equipment items on a case-by-case basis, if it can be demonstrated that extreme financial hardship would occur if the specialty subcontractor had to rent replacement equipment, or if it can be demonstrated that a specialized equipment item is not available by rental.

E. All heavy earthmoving equipment and heavy duty construction-related trucks with engines meeting the requirements of (c) above shall be properly maintained and the engines tuned to the engine manufacturer's specifications.

F. All diesel heavy construction equipment shall not remain running at idle for more than five minutes, to the extent practical.

G. Construction equipment will employ electric motors when feasible.

Verification: The AQCMM shall include in the Monthly Compliance Report:

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

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 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 use gasoline powered light trucks, equivalent of the Ford F150 model, for parabolic mirror washing activities and facility maintenance. Only new trucks meeting California on-road vehicle emission standards shall be purchased for use at the site. In addition, only electrical powered all-terrain vehicles shall be used to support the maintenance crew within the facility.

Electric or alternative vehicle/fuel types may be allowed assuming that the emission profile for alternative fuel vehicles, including fugitive dust generation emissions, is comparable to the vehicles types identified above.

Verification: At least 60 days prior to the start commercial production, the project owner shall submit to the CPM a copy of the plan that identifies the size and type of the on-site electric and fossil-fueled 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-SC7 The project owner shall provide a site operations dust control plan that:

A. describes the wind erosion control techniques such as windbreaks, water, and chemical dust suppressants that shall be used on areas that could be disturbed by vehicles or wind; and

B. identifies the location of signs throughout the facility that will limit traveling on unpaved portion of roadways to solar equipment maintenance vehicles only. In addition, vehicle speed shall be limited to no more than 10 miles per hour on these unpaved roadways.

Verification: At least 60 days prior to start of commercial operation, the project owner shall submit to the CPM a copy of the plan that identifies the dust and erosion control procedures that will be used during operation of the project and that identifies all locations of the speed limit signs. At least 60 days after commercial operation, the project owner shall provide to the CPM a report identifying the locations of all speed limit signs, and a copy of the project employee and contractor training manual that clearly identifies that project employees and contractors are required to comply with the dust and erosion control procedures and on-site speed limits.

AQ-SC8 The project owner shall provide the CPM copies of all District issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) 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 air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or U.S. Environmental Protection Agency (U.S. EPA), and any revised permit issued by the District or U.S. EPA, for the project.

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

DISTRICT CONDITIONS

District Final Determination of Compliance Conditions (KCAPCD 2009)

ATC Nos. 0369001 and ‘002 (30.0-Mmbtu/Hr Natural Gas Fueled Boilers No. 1 and No. 2)

Equipment Description

30.0-MMBtu/hr (900-hp) natural gas fueled boiler with low-NOx burner system.

Design Conditions

AQ-1 Boiler shall be fueled exclusively with natural gas. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-2 Boiler described above shall be equipped with low NOx burner and be in accordance with manufacturer’s specifications. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-3 Boiler exhaust stack shall be equipped with provisions for collection of pollutant samples in manner consistent with U. S. EPA test methods. (Rule 210.1)

Verification: The project owner shall provide facilities, utilities, and safety equipment for source testing and inspections upon request of the District, ARB, and the Energy Commission.

Operational Conditions

AQ-4 Visible emissions from boiler exhaust stack shall not exceed 5% opacity or Ringelmann No. 1/4. (Rule 210.1 BACT Requirement)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-5 Boiler operation shall not exceed 1000-hours/year without prior District approval. (Rule 210.1)

Verification: The project owner shall submit to the CPM the boiler operating data demonstrating compliance with this condition as part of the Annual Operation Report.

AQ-6 Boiler exhaust concentration of sulfur oxides (calculated as SO_2) shall not exceed 2000 parts per million on a volume basis (ppmv). (Rule 407)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-7 Volume of natural gas used as fuel for boiler shall not exceed 28.6 million standard cubic feet per year (MMscf/yr). (Rule 210.1)

Verification: The project owner shall submit to the CPM the boiler fuel use data demonstrating compliance with this condition as part of the Annual Operation Report.

AQ-8 Operator shall comply with applicable monitoring, testing, and recordkeeping requirements of Rule 425.2. (Rule 425.2)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-9 Operator shall maintain annual records of fuel use. (Rule 425.2)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-10 Equipment shall be maintained according to manufacturer's specifications to ensure compliance with emissions limitations. (Rules 209 and 210.1)

Verification: The project owner shall submit maintenance reports for all equipment to the CPM as part of Annual Compliance Report. As part of the Annual Compliance Report, the project owner shall include information on any maintenance performed on the boiler.

AQ-11 No emission resulting from use of this equipment shall cause injury, detriment, nuisance, annoyance to or endanger comfort, repose, health or safety of any considerable number of persons or public. (Rule 419 and CH & SC 41700)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

Compliance Testing Requirements

AQ-12 Boiler stack shall be equipped with sampling ports (in accordance with California Air Resources Board Standards), sampling platform, access to sampling platforms, and utilities for sampling equipment to perform source-sampling operations. (Rule 108.1)

Initial compliance with NOx emission limits shall be verified by compliance test utilizing test methods listed in Subsection VI.B of Rule 425.2 within 60-days of District initial start-up inspection. (Rule 210.1)

Initial testing for Rule 425.2 shall commence within 60-days after annual boiler heat attains or exceeds 90,000 therms (9,000-MMBtu). Boiler shall be tested in accordance with test methods listed in Subsection VI.B and in accordance to schedule in Subsection VI.C of Rule 425.2. (Rule 425.2)

Should inspection reveal conditions indicative of non-compliance, compliance with any emission limitations shall be verified, within 60 days of District request. Test results shall be submitted to KCAPCD within 30 days after test completion. (Rule 108.1 and 210.1)

Verification: The project owner shall notify the District and the CPM within fifteen working days before the execution of the compliance test required in this condition. The test results shall be submitted to the District and to the CPM within 30 days after test completion.

Emission Limits

AQ-13 Emissions rate of each air contaminant from this unit shall not exceed following limits:

Particulate Matter (PM10):	0.22	lb/hr
	3.04	lb/day
	0.11	ton/yr
Sulfur Oxides (SOx as SO_2):	0.02	lb/hr
	0.24	lb/day
	0.01	ton/yr
Oxides of Nitrogen (NO_2):	9	ppmv @ 3% O_2 (Rule 210.1 BACT Rqmt.)
	0.33	lb/hr
	4.62	lb/day
	0.17	ton/yr
Volatile Organic Compounds (VOC):	0.16	lb/hr
(as defined in Rule 210.1)	2.20	lb/day
	0.08	ton/yr
Carbon Monoxide:	50	ppmv
	1.11	lb/hr
	15.54	lb/day
	0.56	ton/yr

(Emissions limits established pursuant to Rule 210.1, unless otherwise noted.)

Compliance with maximum daily emission limits shall be verified by source operator (with appropriate operational data and recordkeeping to document maximum daily emission rate) each day source is operated and such documentation of compliance shall be retained and made readily available to District for period of three years. (Rules 209 and 210.1)

Verification: As part of the Annual Compliance Report, the project owner shall include information on operating emission rates. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

ATC No. 0369003 (Forced Draft Cooling Tower with 11 Cells and High Efficiency Drift Eliminator)

Equipment Description

A. Eleven 140-MMBtu (13,600-gpm) Cooling Tower Cells

B. Eleven 250-hp Cooling Tower Fans

C. Two 2,000-hp (79,000-gpm) Cooling Water Pumps

D. Make-Up Water Tank

E. 50-hp Make-Up Water Pump

AQ-14 No hexavalent chromium containing compounds shall be added to cooling tower circulating water. (Rule 429.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-15 Drift eliminator drift rate shall not exceed 0.0005%. (Rule 210.1)

Verification: The manufacturer guarantee data for the drift eliminator, showing compliance with this condition, shall be provided to the CPM and the District 30 days prior to cooling tower operation.

AQ-16 Cooling tower total dissolved solids (TDS) shall not exceed 1600 mg/liter (0.01335 lb/gal). (Rule 210.1)

Verification: The cooling tower recirculating water TDS content shall be tested as required in Condition **AQ-22** and those tests shall be provided in the Annual Compliance Report. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-17 Cooling water volumetric flow rate shall not exceed 149,000-gal/minute. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-18 Compliance with hourly PM10 emission rate shall be determined by the product of the following factors: circulating water rate (gpm), total dissolved solids in blowdown water (lb/gal), and design drift rate (%). (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-19 Operator shall comply with applicable monitoring, testing, and recordkeeping requirements of Rule 429.1. (Rule 429.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-20 Equipment shall be maintained according to manufacturer's specifications to ensure compliance with emissions limitations. (Rules 209 and 210.1)

Verification: The project owner shall submit maintenance reports for all equipment to the CPM as part of Annual Compliance Report. As part of the Annual Compliance Report, the project owner shall include information on the date, time, and duration of any violation of this permit condition.

AQ-21 No emission resulting from use of this equipment shall cause injury, detriment, nuisance, annoyance to or endanger comfort, repose, health or safety of any considerable number of persons or public. (Rule 419 and CH & SC 41700)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-22 Compliance with PM10 emission limits shall be determined by continuous conductivity monitoring of blowdown water with results available to District staff available to District staff upon request, and annual calibration verification available to District staff upon request. In-lieu of continuous conductivity monitoring, tests of total solids in blowdown water sample analysis shall be completed at a minimum of once per week by independent laboratory. (Rule 210.1)

Verification: The cooling tower recirculating water TDS content test results and resulting emission estimates shall be shall be provided in the Annual Compliance Report. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

Compliance Testing Requirements

AQ-23 Should inspection reveal conditions indicative of non-compliance, compliance with any emission limitations shall be verified, within 60 days of District request. Test results shall be submitted to KCAPCD within 30 days after test completion. (Rule 108.1, 210.1, and 429.1)

Verification: The project owner shall provide a test protocol to District for approval and CPM for review of any compliance tests proposed to be conducted as required under this condition at least 30 days prior to conducting such tests. The project owner shall notify the District and the CPM within fifteen working days before the execution of any compliance tests required under this condition. The test results shall be submitted to the District and to the CPM within 30 days of the completion of the tests.

Emission Limits

AQ-24 Emissions rate of each air contaminant from this unit shall not exceed following limits:

Particulate Matter (PM_{10}):	0.60 lb/hr 9.55 lb/day 1.74 ton/yr

(Emissions limits established pursuant to Rule 210.1, unless otherwise noted.)

Compliance with maximum daily emission limits shall be verified by source operator (with appropriate operational data and recordkeeping to document maximum daily emission rate) each day source is operated and such documentation of compliance shall be retained and made readily available to District for period of three years. (Rules 209 and 210.1)

Verification: As part of the Annual Compliance Report the project owner shall include information on operating emission rates to demonstrate compliance with this condition. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

ATC No. 0369004 (Six 6000-Gallon Heat Transfer Fluid (HTF) Expansion Tank Vented To Vapor Control System, Including HTF Piping Network)

Equipment Description

A. Six 6,000 Gallon HTF Expansion Tank No. 1 through No. 6 each with PV vent valve,

B. 25-hp Expansion tank pump,

C. HTF Fluid pumps (400-hp),

D. Nitrogen blanket system,

E. HTF piping header,

F. HTF ullage system,

G. Solar field piping,

H. Solar generating system piping, and

I. Piping from expansion tank to vapor control system.

Design Conditions

AQ-25 Each HTF tank shall be connected to a volatile organic compound (VOC) vapor control system (Permit No. 0369005). (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-26 Volume of each tank shall not exceed 6,000-gallons without prior District approval. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

Operational Conditions

AQ-27 HTF expansion vessel shall be gas tight and vent to vapor control system (Permit No. 0369005). (Rule 210.1 BACT Requirement)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-28 The project owner shall establish an inspection and maintenance program to determine, repair, and long leaks in HTF piping network and expansion tanks. Inspection and maintenance program and documentation shall be available to District staff upon request. (Rule 210.1 BACT Requirement)

A. All pumps, compressors and pressure relief devices (pressure relief valves or rupture disks) shall be electronically, audio, or visually inspected once every operating period.

B. All accessible valves, fittings, pressure relief devices (PRDs), hatches, pumps, compressors, etc. shall be inspected quarterly using a leak detection device such as a Foxboro OVA 108 calibrated for methane.

C. VOC leaks greater than 100-ppmv shall be tagged (with date and concentration) and repaired within seven calendar days of detection.

D. VOC leaks greater than 10,000-ppmv shall be tagged and repaired within 24-hours of detection.

E. The project owner shall maintain a log of all VOC leaks exceeding 10,000-ppmv, including location, component type, and repair made.

F. The project owner shall maintain record of the amount of HTF replaced on a monthly basis for a period of five years.

G. Any detected leak exceeding 100-ppmv and not repaired in 7-days and 10,000-ppmv not repaired within 24-hours shall constitute a violation of the District's Authority to Construct (ATC)/Permit to Operate (PTO).

H. Pressure sensing equipment shall be installed that will be capable of sensing a major rupture or spill within the HTF network.

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-29 The following component count shall be utilized to determine fugitive emissions.

Equipment	Service	Count
Valves	Light Liquid	3050
Pump Seals	Light Liquid	4
Connectors*	Light Liquid	7550
Pressure Relief Valve	Gas	6
Open-ended Lines	Light Liquid	44

Verification: The project owner shall provide the District for approval and the CPM for review any requested revisions to the component count listed in this condition 30 days prior to utilizing such component counts for fugitive emission calculations, and shall keep a record of approved changes in the component count in the inspection and maintenance program documentation kept at the site.

AQ-30 Each expansion tank shall have fixed roof without holes, tears, or other such openings, except pressure/vacuum (PV) valves, in the cover which allow the emission of VOC. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-31 All expansion tank hatches shall be kept closed and gap-free, except during maintenance, inspection, or repair. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-32 Tank roof appurtenances shall not exhibit emissions exceeding 10,000-ppmv as methane measured with an instrument calibrated with methane and conducted in accordance with U.S. Method 21. (Rule 411)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-33 Each tank shall be maintained leak-free. A "leak" is defined as the dripping of liquid volatile organic compounds at a rate of three or more drops per minute, or vapor volatile organic compounds in excess of 10,000-ppm as equivalent methane as determined by EPA Test Method 21. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-34 Equipment shall be maintained according to manufacturer's specifications to ensure compliance with emissions limitations. (Rules 210.1 and 209)

Verification: The project owner shall submit maintenance reports for all equipment to the CPM as part of Annual Compliance Report.

AQ-35 Compliance with all operational conditions shall be verified by appropriate recordkeeping, including records of operational data needed to demonstrate compliance. Such records shall be kept on site in readily available format. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-36 No emission resulting from use of this equipment shall cause injury, detriment, nuisance, annoyance to or endanger comfort, repose, health, or safety of any considerable number of persons or public. (Rule 419 and CH&SC Sec 41700)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-37 The District shall be notified of any breakdown conditions in accordance with Rule 111 (Equipment Breakdown). (Rule 111)

Verification: The project owner shall provide equipment breakdown notification as required by District Rule 111 and shall provide such data to the CPM within five days of District notification and shall provide equipment breakdown records in the Annual Compliance Report.

Compliance Testing Requirements

AQ-38 Should inspection reveal conditions indicative of non-compliance, compliance with hourly and concentration emission limits for VOC shall be verified pursuant to Rule 108.1 and KCAPCD Guidelines for Compliance Testing, within 60 days of District request.

Verification: The project owner shall provide a test protocol to District for approval and CPM for review of any compliance tests proposed to be conducted as required under this condition at least 30 days prior to conducting such tests. The project owner shall notify the District and the CPM within fifteen working days before the execution of any compliance tests required under this condition. The test results shall be submitted to the District and to the CPM within 30 days of the completion of the tests.

Emission Limits

AQ-39 Emissions rate of each air contaminant from this unit shall not exceed following limits:

Fugitive Emissions (Connectors, Pumps, etc.)

Volatile Organic Compounds (VOC):	21.39 lb/day 3.90 ton/yr

(Emissions limits established pursuant to Rule 210.1, unless otherwise noted.)

Compliance with maximum daily emission limits shall be verified by source operator (with appropriate operational data and recordkeeping to document maximum daily emission rate) each day source is operated and such documentation of compliance shall be retained and made readily available to District for period of three years. (Rules 209 and 210.1)

Verification: As part of the Annual Compliance Report the project owner shall include information on operating emission rates to demonstrate compliance with this condition. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

ATC No. 0369005 (Vapor Control System)

Equipment Description

A. Piping from expansion tanks (Permit Nos. 0369004) to vapor control system, and

B. Two Granular Activated Carbon (GAC) adsorption units in series each with 1,000-lb GAC vessel, and sampling ports at entrance and exhaust.

Design Conditions

AQ-40 Vapor control system shall serve HTF expansion tanks and HTF piping system listed on Permit No. 0369004. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-41 Carbon adsorption system shall provisions for monitoring between carbon beds and exhaust of carbon adsorption system. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

Operational Conditions

AQ-42 Carbon adsorption system shall be operated during heat transfer fluid (HTF) expansion system operation and during operation of HTF Ullage system. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-43 Control efficiency of carbon adsorption vessels shall be at least 95%. (Rule 210.1)

Verification: The project owner shall provide the District and CPM carbon adsorption manufacturer guarantee data showing compliance with this condition at least 30 days prior to the installation of the carbon adsorption vessels.

AQ-44 Vapor samples shall be taken monthly between carbon beds and at the exhaust carbon adsorption system and tested for carbon breakthrough. (Rule 210.1)

Verification: The project owner shall keep the monthly vapor sample data at the site and shall provide a summary of the vapor sample data as part of the Annual

Compliance Report. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-45 Carbon breakthrough shall be defined as VOC concentration of 10-ppmv as hexane measured after primary carbon bed measured with a flame ionization detector (FID) or photo ionization detector (PID). (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-46 Primary carbon bed shall be replaced upon indication of carbon breakthrough. (Rule 210.1)

Verification: The project owner shall keep primary carbon bed replacement records on site and shall provide such records as part of the Annual Compliance Report. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-47 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with application under which this permit is issued. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-48 Equipment shall be maintained according to manufacturer's specifications to ensure compliance with emissions limitations. (Rules 209 and 210.1)

Verification: The project owner shall submit maintenance reports for all equipment to the CPM as part of Annual Compliance Report.

AQ-49 No emission resulting from use of this equipment shall cause injury, detriment, nuisance, annoyance to or endanger comfort, repose, health, or safety of any considerable number of persons or public. (Rule 419 and CH&SC, Sec 41700)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

Compliance Testing Requirements

AQ-50 Should inspection reveal conditions indicative of non-compliance, compliance with any emission limits for VOC shall be verified pursuant to Rule 108.1 and KCAPCD Guidelines for Compliance Testing, within 60 days of District request.

Verification: The project owner shall provide a test protocol to District for approval and CPM for review of any compliance tests proposed to be conducted as required under this condition at least 30 days prior to conducting such tests. The project owner shall notify the District and the CPM within fifteen working days before the execution of any compliance tests required under this condition. The test results shall be submitted to the District and to the CPM within 30 days of the completion of the tests.

Emission Limits

AQ-51 Emissions rate of each air contaminant from this unit shall not exceed the following emissions limits

Controlled Vapor Emissions:

Volatile Organic Compounds (VOC):	0.63 lb/hr 1.25 lb/day 0.23 ton/yr

(Emissions limits established pursuant to Rule 210.1 unless otherwise noted)

Compliance with maximum daily emission limits shall be verified by source operator (with appropriate operational data and record keeping to document maximum daily emission rate) each day the source is operated and such documentation of compliance shall be retained and made readily available to District for period of three years. (Rules 210.1 and 209)

Verification: As part of the Annual Compliance Report the project owner shall include information on operating emission rates to demonstrate compliance with this condition. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

ATC No. 0369006 (Emergency Firewater Pump Driven By 300-BHP Diesel Piston Engine)

Equipment Description

3000-gallon per minute (gpm) Clarke firewater pump driven by 300-bhp John Deere Tier 3 diesel fueled piston engine

Design Conditions

AQ-52 Engine shall be equipped with turbocharger and aftercooler. (Rule 210.1 BACT Requirement)

Verification: The project owner shall submit the final engine specifications documenting compliance with this condition at least 30 days prior to installation of the engine.

AQ-53 Elapsed time meter shall be installed and maintained indicating cumulative hours of engine operating time. (Rule 210.1)

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the District, ARB, and the Energy Commission.

Operational Conditions

AQ-54 Visible emissions from engine exhaust after engine has reached normal operating temperature shall not equal or exceed 5% opacity or Ringelmann No. ¼ for more than three minutes in any one hour. (Rule 210.1 BACT Requirement)

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the District, ARB, and the Energy Commission.

AQ-55 Exhaust gas particulate matter concentration shall not exceed 0.1 grains/ft3 of gas at standard conditions. (Rule 404.1)

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the District, ARB, and the Energy Commission.

AQ-56 Fuel for diesel piston engine shall conform to California Air Resources Board standards for reformulated diesel fuel (low sulfur, 0.0015% by weight and low aromatic hydrocarbon, 20% by weight). (Rule 210.1 BACT Requirement)

Verification: The project owner shall make the site available for inspection of equipment and fuel purchase records by representatives of the District, ARB, and the Energy Commission.

AQ-57 Equipment shall be maintained according to manufacturer's specifications to ensure compliance with emissions limitations. (Rule 210.1 and Rule 209)

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the District, ARB, and the Energy Commission.

AQ-58 Compliance with all operational conditions shall be verified by appropriate recordkeeping, including records of operational data needed to demonstrate compliance. Such records shall be kept on site in readily available format. (Rule 209)

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the District, ARB, and the Energy Commission.

AQ-59 Operating record of this equipment shall be maintained in format approved in writing by District, kept for minimum of two years, and made available upon request of District personnel. Record shall include, at minimum, days and hours of operation, location of operation, amount of fuel oil supplied to this engine, and date(s), check(s) and certification(s) of injection timing. (Rules 209 and 210.1)

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the District, ARB, and the Energy Commission.

AQ-60 No emission resulting from use of this equipment shall cause injury, detriment, nuisance, annoyance to or endanger comfort, repose, health or safety of any considerable number of persons or public. (Rule 419 and CH&SC 41700)

Verification: The project owner shall make the site available for inspection of equipment and records by representatives of the District, ARB, and the Energy Commission.

AQ-61 Engine operation shall not exceed 200 hours per year without prior District approval. (Rule 210.1)

Verification: As part of the Annual Compliance Report the project owner shall include information on annual engine operating hours to demonstrate compliance with this condition. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-62 Diesel engine driving emergency fire water pump shall comply with Tier 3 emissions standards and Air Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines. (California Code of Regulations 93115, Title 17)

Verification: The project owner shall submit the final engine specifications documenting compliance with this condition at least 30 days prior to installation of the engine.

AQ-63 Engine operation for maintenance and testing shall not exceed 50 hours per year without prior District approval. (Rule 210.1)

Verification: As part of the Annual Compliance Report the project owner shall include information on annual engine operating hours to demonstrate compliance with this condition. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

Compliance Testing Requirements

AQ-64 Should inspection reveal conditions indicative of non-compliance, compliance with any emission limitations shall be verified, within 60 days of District request. Test results shall be submitted to KCAPCD within 30 days after test completion. (Rule 108.1 and 210.1)

Verification: The project owner shall provide a test protocol to District for approval and CPM for review of any compliance tests proposed to be conducted as required under this condition at least 30 days prior to conducting such tests. The project owner shall notify the District and the CPM within fifteen working days before the execution of any compliance tests required under this condition. The test results shall be submitted to the District and to the CPM within 30 days of the completion of the tests.

Emission Limits

AQ-65 Emissions rate of each air contaminant from this unit shall not exceed following limits:

Particulate Matter (PM10):	0.15 gm/bhp-hr 0.10 lb/hr 2.38 lb/day 0.01 ton/yr
Sulfur Oxides (SOx as SO_2):	0.0030 lb/hr 0.0800 lb/day 0.0003 ton/yr
Oxides of Nitrogen (NOx as NO_2):	2.80 gm/bhp-hr 1.85 lb/hr 44.45 lb/day 0.19 ton/yr
Volatile Organic Compounds (VOC): (as defined in Rule 210.1)	0.20 gm/bhp-hr 0.13 lb/hr 3.18 lb/day 0.01 ton/yr
Carbon Monoxide:	1.72 lb/hr 41.28 lb/day 0.17 ton/yr

(Emissions limits established pursuant to Rule 210.1, unless otherwise noted.)

Compliance with maximum daily emission limits shall be verified by source operator (with appropriate operational data and recordkeeping to document maximum daily emission rate) each day source is operated and such documentation of compliance shall be retained and made readily available to District for period of three years. (Rules 209 and 210.1)

Verification: As part of the Annual Compliance Report the project owner shall include information on operating emission rates to demonstrate compliance with this condition. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

ATC No. 0369007 (Bio-Remediation of Hydrocarbon Contaminated Soil)

Equipment Description

A. 400-ft. by 800-ft. bio-remediation/land-farm facility,

B. Irrigation system for bio-remediation/land-farm facility, and

C. Bio-remediation fertilizer for enhanced bio-remediation.

Design Conditions

AQ-66 Bio-remediation area shall be lined with minimum 60-mil high density polyethylene (HDPE) or alternate lining approved by Lahontan Regional Water Quality Board (LRWQB). (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-67 The project owner shall provide District with depth of bio-remediation operation area. (Rule 210.1)

Verification: The project owner shall submit the depth of the bio-remediation operation area to the District and CPM prior to use of the bio-remediation operation area.

Operational Conditions

AQ-68 Visible emissions from bio-remediation/land-farm facility when soil is not actively being added or removed shall not equal or exceed 0% opacity for more than five minutes in any two hour period. (Rule 210.1 BACT Requirement)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-69 The project owner shall have flame ionization detector (FID) or photo ionization detector (PID) on site to measure soil VOC emissions (measured as hexane). (Rule 210.1)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-70 The project owner shall maintain weekly VOC readings of bio-remediation area during any period it is operated. The project owner shall provide protocol for VOC readings, soil acidity (pH), soil moisture content (% weight), soil temperature (°F), and Nutrient Ration (C:N:P) to be approved by District staff. (Rule 210.1)

Verification: The project owner shall provide a protocol for measuring bio-remediation soil VOC content to the District for approval and the CPM for review prior to use of the bio-remediation operation area. The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-71 If soil in bio-remediation area registers a VOC reading of less than 50-ppm by volume, measured three inches above soil surface, with FID or PID compliance with Condition AQ-72 is not required. (Rule 210.1)

Verification: Logs of the bio-remediation soil VOC content measurements shall be kept with specific notation regarding whether VOC readings are above or below 50 ppm by volume. The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

AQ-72 If soil in bio-remediation area registers a VOC reading greater than or equal to 50-ppm (calibrated to methane) by volume, measured three inches above soil surface, with FID or PID bio-remediation operation shall comply with the following conditions. (Rule 210.1)

A. Affected soil stockpile shall be covered with minimum 10-mile plastic sheeting within 24-hours of detection to control emissions during treatment until VOC readings 3-inches above the uncovered soil stockpile are less than 50-ppmv. (Rule 210.1)

B. Covered soil stockpile shall be treated by enhanced bio-remediation using accepted environmental engineering practices to maintain conditions suitable for bio-remediation. Soil in stockpiles shall be conditioned as necessary through addition of nutrients, moisture and air as needed.

C. The following parameters in treatment area shall be monitored according to approval protocol. VOC readings over treatment area in use, soil acidity (pH), soil moisture content (% weight), soil temperature (°F), and Nutrient Ratio (C:N:P).

D. Records of soil treatment and monitoring results shall be maintained at the site for a period of at least 5-years, and

E. If bio-remediation operation is not effective after two months (i.e. VOC readings show no reduction in VOC content), the project owner shall propose alternate method of soil remediation for District approval.

Verification: Logs of the bio-remediation soil VOC content measurements shall be kept with specific notation regarding whether VOC readings are above or below 50 ppm by volume with other records required by this condition. A summary of the bio-remediation operation area records to demonstrate ongoing compliance with this condition shall be provided in the Annual Compliance Report.

AQ-73 Soil moisture content shall be maintained according to District approved protocol. (Rule 210.1)

Verification: A summary of the bio-remediation operation area records to demonstrate ongoing compliance with this condition shall be provided in the Annual Compliance Report.

AQ-74 Compliance with all operational conditions shall be verified by appropriate recordkeeping, including records of operational data needed to demonstrate compliance. Such records shall be kept on site in readily available format. (Rule 209)

Verification: The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-75 No emission resulting from use of this equipment shall cause injury, detriment, nuisance, annoyance to or endanger comfort, repose, health or safety of any considerable number of persons or public. (Rule 419 and CH&SC 41700)

Verification: The project owner shall make the site available for inspection of records and equipment by representatives of the District, ARB, and the Energy Commission.

Compliance Testing Requirements

AQ-76 Should inspection reveal conditions indicative of non-compliance, compliance with any emission limitations shall be verified, within 60 days of District request. Test results shall be submitted to KCAPCD within 30 days after test completion. (Rule 108.1 and 210.1)

Verification: The project owner shall provide a test protocol to District for approval and CPM for review of any compliance tests proposed to be conducted as required under this condition at least 30 days prior to conducting such tests. The project owner shall notify the District and the CPM within fifteen working days before the execution of any compliance tests required under this condition. The test results shall be submitted to the District and to the CPM within 30 days of the completion of the tests.

Emission Limits

AQ-77 Emissions rate of each air contaminant from this unit shall not exceed the following emissions limits:

Volatile Organic Compounds (VOC):	0.10 lb/day
(as defined in Rule 210.1)	0.02 ton/yr

(Emissions limits established pursuant to Rule 210.1 unless otherwise noted)

Compliance with maximum daily emission limits shall be verified by source operator (with appropriate operational data and recordkeeping to document maximum daily emission rate) each day source is operated and such documentation of compliance shall be retained and made readily available to District for period of three years. (Rules 209 and 210.1)

Verification: As part of the Annual Compliance Report the project owner shall include information on operating emission rates to demonstrate compliance with this condition. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

Facility Wide Conditions

Construction Activity

AQ-78 All construction phase emissions shall be controlled utilizing reasonably available control provisions, e.g. construction site and unsurfaced roadway dust control, conscientious maintenance of mobile and piston engine-powered equipment, etc.

<u>Verification:</u> The project owner shall comply with the requirements of Conditions AQ-SC1 through AQ-SC5.

Air Toxics

AQ-79 Facility shall comply with California Health and Safety Code Sections 44300 through 44384. (Rule 208.1)

<u>Verification:</u> The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

ACRONYMS

AAQS	Ambient Air Quality Standard
AERMOD	ARMS/EPA Regulatory Model
AFC	Application for Certification
amsl	above mean sea level
APCD	Air Pollution Control District (KCAPCD)
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMP	Air Quality Management Plan
ARB	California Air Resources Board
ATC	Authority to Construct
ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
bhp	brake horsepower
BSEP	Beacon Solar Energy Project
Btu	British thermal unit
CAAQS	California Ambient Air Quality Standard
CEC	California Energy Commission (or Energy Commission)
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPM	(CEC) Compliance Project Manager
EIR	Environmental Impact Report
ERC	Emission Reduction Credit
FDOC	Final Determination Of Compliance
HTF	Heat Transfer Fluid (Therminol)
GHG	Greenhouse Gas
gr	Grains (1 gr $\cong$ 0.0648 grams, 7000 gr = 1 pound)
hp	horsepower
H_2S	Hydrogen Sulfide
KCAPCD	Kern County Air Pollution Control District
lbs	Pounds
LORS	Laws, Ordinances, Regulations and Standards
MCR	Monthly Compliance Report
MDAB	Mojave Desert Air Basin

mg/m^3	milligrams per cubic meter
MMBtu	Million British thermal units
MW	Megawatts (1,000,000 Watts)
NAAQS	National Ambient Air Quality Standard
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates
NOx	Oxides of Nitrogen *or* Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
O_3	Ozone
OLM	Ozone Limiting Method
PDOC	Preliminary Determination Of Compliance
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
PSA	Preliminary Staff Assessment (this document)
PSD	Prevention of Significant Deterioration
PTO	Permit to Operate
scf	Standard Cubic Feet
SO_2	Sulfur Dioxide
SO_3	Sulfate
SOx	Oxides of Sulfur
SR	State Route
tpy	tons per year
U.S. EPA	United States Environmental Protection Agency
$\mu g/m^3$	Microgram per cubic meter
VOC	Volatile Organic Compounds

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APPENDIX AIR-1 - GREENHOUSE GAS EMISSIONS

Matthew Layton, P.E.

SUMMARY OF CONCLUSIONS

The Beacon Solar Energy Project (BSEP) is a solar project that would emit considerably less greenhouse gases (GHG) than existing power plants and most other generation technologies, and thus would contribute to continued improvement of the overall western United States, and specifically California, electricity system GHG emission rate average. Staff recommends reporting of the GHG emissions as the California Air Resources Board develops greenhouse gas regulations and/or trading markets required by the California Global Warming Solutions Act of 2006 (AB 32 Núñez, Chapter 488, Statutes of 2006). The project may be subject to additional reporting requirements and GHG reductions or trading requirements as these regulations become more fully developed and implemented.

Staff concludes that typically the short-term emission of greenhouse gases during construction would likely be sufficiently reduced and would, therefore, not be significant. The Beacon Solar Energy Project, as a solar project with a nightly shutdown would operate less than 60% of capacity and is therefore not subject to the requirements of SB 1368 (Perata, Chapter 598, Statutes of 2006) and the Greenhouse Gas Emission Performance Standard. However, the Beacon Solar Energy Project would easily comply with the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard.

INTRODUCTION

Greenhouse gas (GHG) emissions are not criteria pollutants, but they are discussed in the context of cumulative impacts. The state has demonstrated a clear willingness to address global climate change through research, adaptation and inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local laws and policies in **Greenhouse Gas Table** 1 pertain to the control and mitigation of greenhouse gas emissions. Staff’s analysis examines the project’s compliance with these requirements.

Greenhouse Gas Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
State	
AB 32 Núñez, Chapter 488, Statutes of 2006	California Global Warming Solutions Act of 2006. This act requires the California Air Resources Board (ARB) to enact standards that will reduce GHG emission to 1990 levels. Electricity production facilities will be regulated.
SB 1368 Perata, Chapter 598, Statutes of 2006	Greenhouse Gas Emission Performance Standard. This regulation prohibits utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 mt CO_2/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO_2/MWh)

GLOBAL CLIMATE CHANGE AND ELECTRICITY PRODUCTION

There is scientific consensus that climate change is occurring and that human activity contributes to that change. Man-made emissions of greenhouse gases, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. Indeed, the California Legislature finds that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California" (Cal. Health & Safety Code, sec. 38500, division 25.5, part 1).

In 1998, the Energy Commission identified a range of strategies to prepare for an uncertain climate future, including a need to account for the environmental impacts associated with energy production, planning, and procurement (CEC 1998, p.5). In 2003, the Energy Commission recommended that the state require reporting of greenhouse gases (GHG) or global climate change[7] emissions as a condition of state licensing of new electric generating facilities (CEC 2003, IEPR p. 42). In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the California Air Resources Board (ARB) to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020.[8] To achieve this, ARB has a mandate to define the 1990 emissions levels and achieve the maximum technologically feasible and cost-effective GHG emission reductions.

The ARB adopted early action GHG reduction measures in October 2007 and adopted mandatory reporting requirements and the 2020 statewide target in December 2007. On December 11, 2008, ARB adopted a scoping plan that identifies emission reductions from significant sources of GHG via regulations, market mechanisms, and other actions. ARB staff is drafting regulatory language to implement its plan and will hold additional public workshops on each measure, including market mechanisms (ARB 2006). The regulations must be effective by January 1, 2011 and mandatory compliance commences on January 1, 2012.

[7] Global climate change is the result of greenhouse gases, or emissions with global warming potentials, affecting the energy balance, and thereby, climate of the planet. The term greenhouse gases (GHG) and global climate change (GCC) gases are used interchangeably.

[8] Governor Schwarzenegger has also issued Executive Order S-3-05 establishing a goal of 80% below 1990 levels by 2050.

Examples of strategies that the state might pursue for managing GHG emissions in California, in addition to those recommended by the Energy Commission and the Public Utilities Commission are identified in the California Climate Action Team's Report to the Governor (CalEPA 2006). Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). It is possible that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will be based on cost-effectiveness (i.e., the greatest effect for the least cost). For example, the ARB proposes a 40% reduction in GHG from the electricity sector, even though that sector currently only produces about 25% of the state GHG emissions. In response, in September 2008 the Energy Commission and the Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches, and identified regulation points should ARB decide that a multi-sector cap and trade system is warranted.

The Energy Commission's *2007 Integrated Energy Policy Report* (IEPR) also addresses climate change within the electricity, natural gas, and transportation sectors. For the electricity sector, it recommends such approaches as pursuing all cost-effective energy efficiency measures and meeting the Governor's stated goal of a 33% renewable portfolio standard.

SB 1368[9], enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Emission Performance Standard of 0.500 metric tonnes CO_2 per megawatt-hour[10] (1,100 pounds CO_2/MWh). Specifically, the Emission Performance Standard (EPS) applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California.[11] If a project, instate or out of state, plans to sell base load electricity to California utilities, the utilities will have to demonstrate that the project complies with the EPS. *Base load* units are defined as units that operate at a capacity factor higher than 60% of the year. As a project operating less than 60% per year, BSEP is not required to comply with the SB 1368 EPS.

In addition to these programs, California is involved in the Western Climate Initiative, a multi-state and international effort to establish a cap and trade market to reduce greenhouse gas emissions in the western United States and the Western Electricity Coordinating Council (WECC). The timelines for the implementation of this program are similar to those of AB 32, with full roll-out beginning in 2012. And as with AB 32, the electricity sector has been a major focus of attention.

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[9] Public Utilities Code § 8340 et seq.

[10] The Emission Performance Standard only applies to carbon dioxide, and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

[11] See Rule at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm

PROJECT GREENHOUSE GAS EMISSIONS

The generation of electricity using fossil fuels, even in a back-up generator at a thermal solar plant, produces air emissions known as greenhouse gases in addition to the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. Greenhouse gas emissions contribute to the warming of the earth's atmosphere, leading to climate change. For fossil fuel-fired power plants and equipment, these include primarily carbon dioxide, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 – often from unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment, and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very large relative global warming potentials. Global warming potential is a relative measure, compared to carbon dioxide, of a compound's residence time in the atmosphere and ability to warm the planet. Mass emissions of GHG are converted into carbon dioxide equivalent (CO_2-equivalnet) metric tonnes for ease of comparison.

CONSTRUCTION

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in short-term, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. The construction would last over 25 months. The applicant provided a greenhouse gas emission estimate for the entirety of the main solar facility site, gas line, and transmission line construction activities. The greenhouse gas emissions estimate, presented below in **Greenhouse Gas Table 2,** were converted by the applicant into CO_2-equivalent and totaled.

Greenhouse Gas Table 2
Beacon Estimated Potential Construction Greenhouse Gas Emissions

Construction Element	CO_2 Equivalent (metric tonnes) [a]
Solar Facility Construction	15,047
Gas Line Construction	2,041
Transmission Line Construction	176
Construction Total	17,265

Source: BS 2009a
[a] One metric tonne (mt) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms

OPERATIONS

Operation of the proposed BSEP project would cause GHG emissions from the facility maintenance fleet and employee trips, two natural gas fueled boilers, emergency fire pump IC engine, and sulfur hexafluoride emissions from new electrical component equipment.

Greenhouse Gas Table 3 shows what the proposed project, as permitted, could potentially emit in greenhouse gases on an annual basis. All emissions are converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled. For this solar project the primary fuel is greenhouse gas free, but there is fuel use in the boilers used to shorten startup times and keep the heat transfer fluid from freezing. Other comparatively large GHG emission sources for this project are the maintenance and worker vehicles and the SF_6 equipment leakage.

Greenhouse Gas Table 3
Estimated BSEP Potential Operating Greenhouse Gas Emissions

	CO_2-equivalent (metric tonnes [a] per year)
Boilers	3176
Fire Pump Engine	7.8
Maintenance Vehicles	72.6
Worker Vehicles [b]	470.2
Equipment Leakage (SF_6)	26.0
Total Project GHG Emissions – mt CO_2–equivalent per year	**3,752.6**
Facility MWh per year [c]	600,000
Facility GHG Performance (mt CO_2-equivalent per MW)	0.006

Sources: BS 2008a, BS 2008g
[a] One metric tonne (mt) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] Assume 66 full time equivalent workers commuting 60 miles round trip five times a week.
[c] BS 2008a, page 2-6.

The proposed project would be permitted, on an annual basis, to emit over 3,700 metric tonnes of CO_2-equivalent per year if operated at its maximum permitted level. Since BSEP, as a solar project with a nightly shutdown will operate less than 60% of capacity, the project is not subject to the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard. However, the BSEP, at 0.006 mt CO_2-equivalent/MWh, would easily comply with the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard of 0.500 mt CO_2/MWh.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses three kinds of impacts: construction, operation, and cumulative effects. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation. Cumulative impacts analysis assesses the impacts that result from the proposed project's incremental effect viewed over time.

CONSTRUCTION IMPACTS

Staff does not believe that the small GHG emission increases from construction activities would be significant for several reasons. First, the period of construction will be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meet the latest emissions standards would further minimize greenhouse gas emissions since staff believes that the use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. However, staff will work with the applicant to more fully define the construction greenhouse gas emission for the final staff assessment.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

The proposed BSEP promotes the state's efforts to improve GHG electrical generation efficiencies and, therefore, reduce the amount of natural gas used by electricity generation and greenhouse gas emissions. As the *2007 Integrated Energy Policy* Report (CEC 2007a, p. 184) noted:

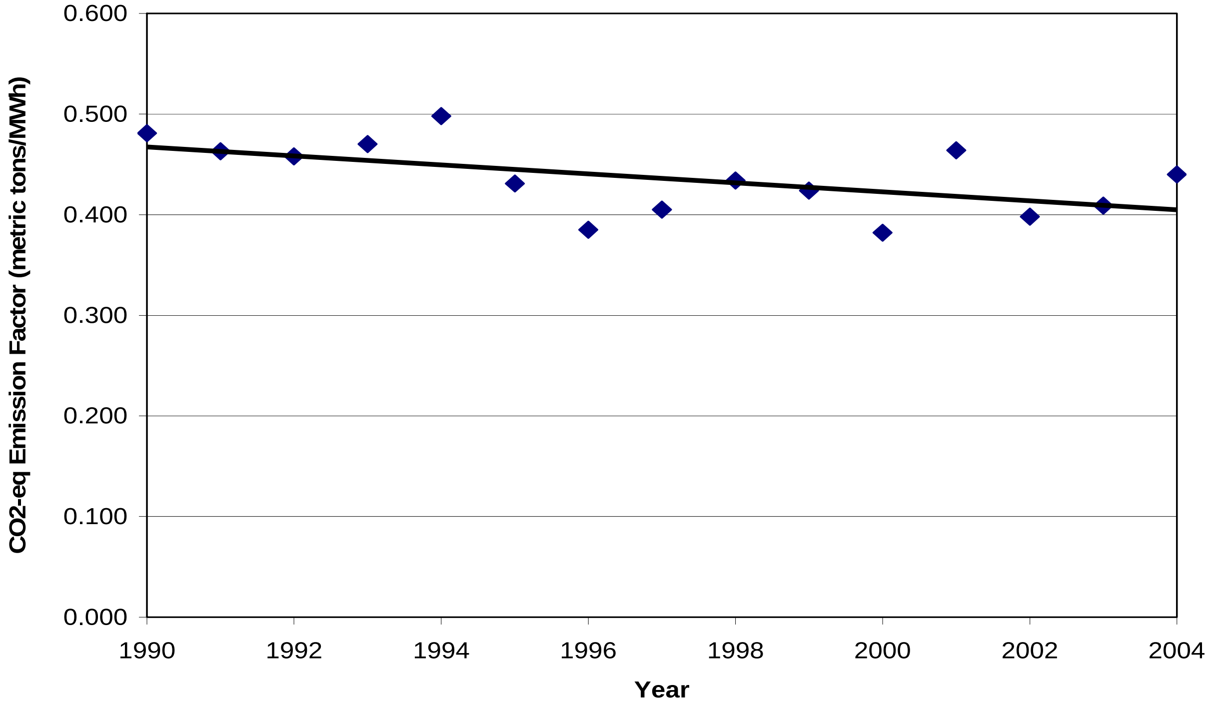
> New natural gas-fueled electricity generation technologies offer efficiency, environmental, and other benefits to California, specifically by reducing the amount of natural gas used—and with less natural gas burned, fewer greenhouse gas emissions. Older combustion and steam turbines use outdated technology that makes them less fuel- and cost-efficient than newer, cleaner plants.… The 2003 and 2005 IEPRs noted that the state could help reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas power plants and replace or repower them with new, more efficient power plants.

Thus, in the context of the Energy Commission's *Integrated Energy Policy Report*, the BSEP - solar-powered, limited natural gas use, limited GHG emissions and likely replacement of older existing plant capacity, furthers the state's strategy to promote generation system efficiency and reduce fuel use and GHG emissions.

System Averages

Because most power plants are interconnected to a utility grid, and in turn to the WECC, it is also important to look at the proposed project in the context of all electricity systems delivering electricity to California consumers. **Greenhouse Gas Figure 1** shows the trends in GHG emission rates for each MWh consumed in California. From 1990 to 2004, California electricity became almost 20% cleaner on a GHG basis. This improvement was due in part to retirements of dirtier, less efficient plants, despite electricity demand growth of almost 20% from 1990 to 2004. Note that the trend line, a linear regression of the annual GHG emission rates, is a better representation of the statewide GHG emission rates than the actual number in any one year. GHG emissions and electricity consumption can vary from year to year due to variations in the availability of hydroelectric power, economic activity, and anomalous events such as the energy crisis of 2000-2001 and unusually warm weather conditions in 2004.

Greenhouse Gas Figure 1
GHG Emissions per Megawatt-hour Consumed in California



Source: ARB 2008f and CEC 2007b.

The proposed project, if it operates at its maximum permitted level, would have a GHG emission rate (0.006 mt CO_2-equivalent/MWh) that is significantly below the system-wide average (the trend line in 2004 is approximate 0.400 mt CO_2-equivalent/MWh), thus would likely contribute to improve the overall system average. Because of the complex interchange among facilities that make up California's electricity system, it is possible that this project could displace electricity that may otherwise be generated by more GHG intensive facilities, such as out-of-state coal plants or local old inefficient peaking units. However, even though staff can identify how many gross GHG emissions and emission rate are attributable to a project, it is difficult to determine whether this will result in a net increase or decrease of these emissions, and, if so, by how much. Thus, it would be speculative in this analysis to conclude that any given electricity generation project results in a cumulatively significant adverse impact resulting from greenhouse gas emissions.

Additionally, the quickly evolving GHG regulatory efforts currently being formulated may shortly establish the best *fora* for addressing GHG emissions from power plants rather than attempting to do so on an ad hoc or plant-by-plant basis. The applicant's goal is to have BSEP operational by the third quarter of 2011. ARB will have set forth each sector's reduction requirements as of January of 2009, followed by the adoption of specific regulations by January of 2011.

Ultimately, ARB's AB 32 regulations will address both the degree of electricity generation emissions reductions, and the method by which those reductions will be achieved, through the programmatic approach currently under its development. That regulatory approach will presumably address emissions not only from the newer, more efficient, and lower emitting facilities licensed by the Energy Commission, but also the older, higher-emitting facilities not subject to any GHG reduction standard that this agency could impose. This programmatic approach is likely to be more effective in reducing GHG emissions overall from the electricity sector than one that merely relies on displacing out-of-state coal plants (“leakage”) or older “dirtier” facilities.

As ARB codifies accurate GHG inventories and methods, it may become apparent that relative contributions to the inventories may not correlate to relative ease and cost-effectiveness of the GHG emission reductions necessary to achieve the 1990 GHG level. Though it has not yet been determined, the electricity sector may have to provide less or more GHG reductions than it would have otherwise been responsible for on a pro-rata basis.

To facilitate ARB’s future regulatory regime, staff recommends Condition of Certification **GHG-1**, which requires the project owner to report the quantities of relevant GHGs emitted as a result of electric power production until such time that AB 32 is implemented and its reporting requirements are in force. It is possible that no reporting will ever be required by this condition if ARB’s reporting requirements are in force prior to the first calendar year of plant operation. However, staff believes that **GHG-1**, with the reporting of GHG emissions, will enable the project to be consistent with the policies described above and the regulations that ARB adopts, and provide the information to demonstrate compliance with any applicable EPS that could be enacted in the next few years. The GHG emissions to be reported in **GHG-1**, are carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, HFCs and PFCs emissions that are directly associated with the production and transmission of electric power.

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 entire assessment is a cumulative impact assessment. The project alone would not be sufficient to change global climate, but would emit greenhouse gases and therefore has been analyzed as a potential cumulative impact in the context of existing GHG regulatory requirements and GHG energy policies.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The project will be subject to compliance with AB 32 requirements once they are determined by ARB. How the project will comply with these ARB requirements is speculative at this time but compliance will be mandatory. The GHG emissions reporting requirement under **GHG-1** does not imply that the project, as defined, will comply with the potential reporting and reduction regulations being formulated under AB 32. The project may have to provide additional reports and GHG reductions, depending on the reporting requirements of the new regulations expected from ARB.

Since this power project would be permitted for less than a 60% annual capacity factor, the project is not subject to the requirements of SB 1368 and the Emission Performance Standard.

NOTEWORTHY PUBLIC BENEFITS

Greenhouse gas related noteworthy public benefits include the construction of renewables and low-GHG emitting generation technologies and the potential for successful integration into the California and greater WECC systems.

CONCLUSIONS

The Beacon Solar Energy Project would emit considerably less greenhouse gases (GHG) than existing power plants and most other generation technologies, and thus would contribute to continued improvement of the overall western United States, and specifically California, electricity system GHG emission rate average. Moreover, even if it were a higher GHG emitting power plant, it would be speculative to conclude that the project would result in a cumulatively significant GHG impact. AB 32 emphasizes that GHG emissions reductions must be “big picture” reductions that do not lead to “leakage” of such reductions to other states or countries. If a solar power plant is not built in California, electricity to serve the load will come from another generating source. That could be renewable generation like wind or solar, but it could also be from higher carbon emitting sources such as out-of-state coal imports or old inefficient units that are a still a significant part of the resource mix that serves California.

Staff recommends the interim reporting of the GHG emissions per Condition of Certification **GHG-1** as the Air Resources Board develops greenhouse gas regulations and/or trading markets required by the California Global Warming Solutions Act of 2006 (AB 32). The project may be subject to additional reporting requirements and GHG reduction or trading requirements as these regulations become more fully developed and implemented.

Staff does not believe that the GHG emission increases typical from construction activities would be significant for several reasons. First, the period of construction would be short-term and not ongoing during the life of the project. Additionally, control measures that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards, would further minimize greenhouse gas emissions since staff believes that the use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment. For all these reasons, staff would likely conclude that the short-term emission of greenhouse gases during construction would be sufficiently reduced and would, therefore, not be significant.

The Beacon Solar Energy Project, as a solar project with a nightly shutdown will operate less than 60% of capacity and is therefore not subject to the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard. However, the Beacon Solar Energy Project would easily comply with the requirements of SB 1368 and the Greenhouse Gas Emission Performance Standard.

PROPOSED CONDITIONS OF CERTIFICATION

Staff recommends the following condition of certification to address the greenhouse gas impacts associated with the construction and operation of the BSEP.

STAFF CONDITION

GHG-1 Until the California Global Warming Solutions Act of 2006 (AB 32) is implemented, the project owner shall either participate in a GHG registry approved by the Compliance Project Manager (CPM), or report on a annual basis to the CPM the quantity of greenhouse gases (GHG) emitted as a direct result of facility electricity production.

The project owner shall maintain a record of fuels types and carbon content used on-site for the purpose of power production. These fuels shall include but are not limited to each fuel type burned: (1) in combustion turbines, (2) boilers, heat recovery steam generators, or auxiliary boiler (4) internal combustion engines, (4) flares, (5) for the purpose of startup, shutdown, operation or emission controls, and/or (6) vehicles and equipment used to prepare fuel or maintain generation components.

The project owner may perform annual source tests of CO_2 and CH_4 emissions from the exhaust stacks while firing the facility's primary fuel, using the following test methods or other test methods as approved by the CPM. The project owner shall produce fuel-based emission factors in units of pounds CO_2-equivalent per million British Thermal Units (MMBtu) of fuel burned from the annual source tests. If a secondary fuel is approved for the facility, the project owner may also perform these source tests while firing the secondary fuel.

Pollutant	Test Method
CO_2	EPA Method 3A
CH_4	EPA Method 18 (VOC measured as CH_4)

As an alternative to performing annual source tests, the project owner may use the Intergovernmental Panel on Climate Change (IPCC) Methodologies for Estimating Greenhouse Gas Emissions (MEGGE). If MEGGE is chosen, the project owner shall calculate the CO_2, CH_4 and N_2O emissions using the appropriate fuel-based carbon content coefficient (for CO_2) and the appropriate fuel-based emission factors (for CH_4 and N_2O).

The project owner shall convert the N_2O and CH_4 emissions into CO_2 equivalent emissions using the current IPCC Global Warming Potentials (GWP). The project owner shall maintain a record of all SF_6 that is used for replenishing on-site transformers. At the end of each reporting period, the project owner shall total the mass of SF_6 used and convert that to a CO_2 equivalent emission using the IPCC GWP for SF_6. The project owner shall maintain a record of all PFCs and HFCs that are used for replenishing on-site refrigeration and chillers directly related to electricity production. At the end of each reporting period, the project owner shall total the mass of PFCs and HFCs used and convert that to a CO_2 equivalent emission using the IPCC GWP.

On an annual basis, the project owner shall report the CO_2 and CO_2 equivalent emissions from the described emissions of CO_2, N_2O, CH_4, SF_6, PFCs, and HFCs.

Verification: The project annual greenhouse gas emissions shall be reported, as a CO_2 equivalent, by the project owner to a climate action registry approved by the CPM, or to the CPM as part of the fourth Quarterly or the annual Air Quality Report, until such time that GHG reporting requirements are adopted and in force for the project as part of the California Global Warming Solutions Act of 2006.

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BIOLOGICAL RESOURCES

Susan D. Sanders

SUMMARY OF CONCLUSIONS

Much of the 2,012-acre Beacon Solar Energy Project (BSEP) plant site is barren or sparsely vegetated due to past agricultural disturbances, but the site nevertheless supports a diversity of mammals, birds, and reptiles, including some special-status wildlife species. Grading on the plant site would not directly or indirectly impact sensitive plant communities, rare plants, or wetlands, but would result in direct impacts to some species and in removal of approximately 430 acres of vegetation that provides cover, foraging, and breeding habitat for wildlife. Construction of linear facilities also has potential for impacts to listed species; transmission line construction west of State Route 14 would permanently impact approximately five acres of Mojave creosote bush scrub habitat for desert tortoise (federal- and state-listed as threatened) and Mohave ground squirrel (state-listed as threatened). While construction of the 17.6-mile gas pipeline would occur within the disturbed road shoulder, trenching and construction activities nevertheless could impact special-status species such as burrowing owl, Mohave ground squirrel and desert tortoise. These potential direct and indirect construction impacts to vegetation and wildlife at the plant site and along linear facilities can be reduced to less-than-significant levels with impact avoidance and minimization measures described in staff's proposed Conditions of Certification **BIO-1** through **BIO-8**.

Potential take of desert tortoise and Mohave ground squirrel and loss of habitat for these species would be fully mitigated with staff's proposed Conditions of Certification **BIO-9** through **BIO-12**. The measures described in staff's proposed Condition of Certification **BIO-11** were proposed by the applicant and require acquisition and enhancement of approximately 115 acres (117.4 acres for transmission line Option 2) of habitat suitable for these listed species. The other two conditions specify impact avoidance and minimization measures, as required by the U. S. Fish and Wildlife Service (USFWS) and the California Department of Fish and Game (CDFG). Implementation of these conditions would reduce impacts to desert tortoise and Mohave ground squirrel to less-than-significant levels and would also satisfy the CDFG's requirements under section 2081 of California's Fish and Game Code.

One of the most significant biological impacts of the BSEP is the re-routing of Pine Tree Creek and another dry desert wash on the plant site, resulting in loss of approximately 60 acres of desert wash scrub habitat and 16.0 acres of jurisdictional waters of the state. The vegetation in the desert wash is highly degraded by past agricultural activities, but these washes are nevertheless characterized by natural processes that support recruitment of native desert wash vegetation and provide wildlife habitat. The applicant proposes to replace the desert washes with an engineered channel to the south and east of the project site and to replicate the hydrological and biological functions and processes in this new drainage.

California Energy Commission staff concurs with the applicant's overall goal of replacing the biological functions and values of the impacted desert wash with the re-routed drainage. However, staff considers this issue unresolved and have recommended some changes from the applicant's proposal as to how this goal would be achieved. Staff has also requested that the applicant re-evaluate the design of the proposed channel, as recommended in the **Soil and Water** section, and develop a channel stabilization plan that incorporates bioengineering techniques and native vegetation where appropriate. Staff also recommends that revegetation efforts be monitored for the life of the project rather than for the five years proposed by the applicant. In addition, the applicant will need to acquire in fee or in easement at least 16 acres of state jurisdictional waters within the same watershed and with similar soil permeability, hydrological, and biological functions. These recommendations are described in staff's proposed Condition of Certification **BIO-18.** With implementation of this condition staff anticipates that impacts to 16.0 acres of state waters and loss of the hydrological and biological functions of desert washes at the BSEP site would be mitigated to less-than-significant levels. This condition would also fulfill requirements of California Department of Fish and Game's Lake and Streambed Alteration Agreement program pursuant to Section 1600 et seq. of California's Fish and Game Code.

The BSEP would include 44 acres of evaporation ponds that would collect blowdown water from the cooling towers. The ponds would be a source of significant concern to CDFG, USFWS and staff because they could attract ravens, which in turn prey on desert tortoise, and could also harm waterfowl, shorebirds, and other resident or migratory birds due to elevated levels of selenium or hyper-saline conditions. The applicant has addressed these concerns by proposing several project design features for the evaporation ponds that would discourage bird use and has proposed bird deterrence and monitoring measures to minimize potential harm to birds and reduce the potential to attract ravens. Staff considers this issue unresolved; the **Soils & Water** and **Alternatives** sections discuss a dry-cooling alternative that would eliminate the evaporation ponds, and would therefore eliminate the significant impact to migratory birds and desert tortoise posed by the ponds. This is the alternative preferred by staff, CDFG, and USFWS because it would entirely avoid the impact. However, if this alternative is not adopted and if evaporation ponds continue to be part of the project, staff has requested that the applicant incorporate their recommended measures into a comprehensive draft Evaporation Pond Design, Monitoring, and Management Plan, which should include any revisions to pond size or design recommended in the **Soil and Water** section. Once approved by CDFG, USFWS and staff, the plan can be incorporated into staff's proposed Condition of Certification **BIO-14,** which would minimize the potential adverse effects of the evaporation ponds to less-than-significant levels.

With implementation of staff's proposed conditions of certification, construction and operation of the BSEP would comply with all federal, state, and local laws, ordinances, regulations, and standards relating to biological resources and would mitigate potential impacts to biological resources to less-than-significant levels.

INTRODUCTION

This section of the Preliminary Staff Assessment provides the California Energy Commission (Energy Commission) staff's preliminary analysis of potential impacts to biological resources from the construction and operation of the proposed Beacon Solar

Energy Project (BSEP). Information provided in this document addresses potential impacts to special-status species and areas of critical biological concern. This analysis also describes the biological resources at the project site and at the locations of ancillary facilities. This document explains the need for mitigation, evaluates the adequacy of mitigation proposed by the applicant, and specifies additional mitigation measures to reduce impacts to less-than-significant levels. It also describes compliance with applicable laws, ordinances, regulations, and standards (LORS) and recommends conditions of certification.

This analysis is based, in part, upon information provided in the BSEP Application for Certification (BS 2008a, BS 2008c) and other submittals, responses to staff data requests (BE 2008i, DB 2008d, DB 2008n, DB 2008o), and staff workshops (DB 2008r); site visits by Energy Commission staff on April 17, 2008; and communications with representatives from the California Department of Fish and Game (CDFG) and the United States Fish and Wildlife Service (USFWS).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The applicant will need to abide by the laws, ordinances, regulations, and standards (LORS) during project construction and operation, as listed in **Biological Resources Table 1**.

Biological Resources Table 1
Laws, Ordinances, Regulations, and Standards

Applicable Law	Description
Federal	
Federal Endangered Species Act (Title 16, United States Code, section 1531 et seq., and Title 50, Code of Federal Regulations, part 17.1 et seq.)	Designates and provides for protection of threatened and endangered plant and animal species and their critical habitat. “Take” of a federally-listed species is prohibited without an incidental take permit, which may be obtained through Section 7 consultation (between federal agencies) or a Section 10 Habitat Conservation Plan.
Migratory Bird Treaty (Title 16, United States Code, sections 703 through 711)	Makes it unlawful to take or possess any migratory nongame bird (or any part of such migratory nongame bird) as designated in the Migratory Bird Treaty Act.
Bald and Golden Eagle Protection Act (Title 16, United States Code section 668)	Provides for the protection of the bald eagle and the golden eagle by prohibiting, except under certain specified conditions, the take, possession, and commerce of such birds. The 1972 amendments increased penalties for violating provisions of the act or regulations issued pursuant thereto and strengthened other enforcement measures. Rewards are provided for information leading to arrest and conviction for violation of the act.
State	
California Endangered Species Act of 1984 (Fish and Game Code, sections 2050 through 2098)	Protects California’s rare, threatened, and endangered species. “Take” of a state-listed species is prohibited without an Incidental Take Permit.
California Code of Regulations (Title 14, sections 670.2 and 670.5)	Lists the plants and animals of California that are declared rare, threatened, or endangered.
Fully Protected Species (Fish and Game Code, sections 3511, 4700, 5050, and 5515)	Designates certain species as fully protected and prohibits the take of such species or their habitat unless for scientific purposes (see also California Code of Regulations, Title 14, section 670.7).
Nest or Eggs (Fish and Game Code section 3503)	Protects California’s birds by making it unlawful to take, possess, or needlessly destroy the nest or eggs of any bird.
Migratory Birds (Fish and Game Code section 3513)	Protects California’s migratory birds by making it unlawful to take or possess any migratory nongame bird as designated in the Migratory Bird Treaty Act or any part of such migratory nongame birds.

Significant Natural Areas (Fish and Game Code section 1930 et seq.)	Designates certain areas such as refuges, natural sloughs, riparian areas, and vernal pools as significant wildlife habitat.
California Environmental Quality Act (CEQA), CEQA Guidelines section 15380	CEQA defines rare species more broadly than the definitions for species listed under the state and federal Endangered Species Acts. Under section 15830, species not protected through state or federal listing but nonetheless demonstrable as "endangered" or "rare" under CEQA should also receive consideration in environmental analyses. Included in this category are many plants considered rare by the California Native Plant Society (CNPS) and some animals on the CDFG's Special Animals List.
Streambed Alteration Agreement (Fish and Game Code sections 1600 et seq.)	Regulates activities that may divert, obstruct, or change the natural flow or the bed, channel, or bank of any river, stream, or lake in California designated by CDFG in which there is at any time an existing fish or wildlife resource or from which these resources derive benefit. Impacts to vegetation and wildlife resulting from disturbances to waterways are also reviewed and regulated during the permitting process.
California Native Plant Protection Act of 1977 (Fish and Game Code section 1900 et seq.)	Designates state rare, threatened, and endangered plants.
California Desert Native Plants Act of 1981 (Food and Agricultural Code section 80001 et seq. and California Fish and Game Code sections 1925-1926)	Protects non-listed California desert native plants from unlawful harvesting on both public and private lands in Imperial, Inyo, Kern, Los Angeles, Mono, Riverside, San Bernardino, and San Diego counties. Unless issued a valid permit, wood receipt, tag, and seal by the commissioner or sheriff, harvesting, transporting, selling, or possessing specific desert plants is prohibited.
Local	
Kern County General Plan Land Use, Open Space, and Conservation Element (Kern County 2007)	Directs the county to work closely with state and federal agencies to assure that discretionary projects avoid or minimize impacts to fish, wildlife, and botanical resources.

SETTING

PROJECT SITE AND DESCRIPTION

Beacon Solar, LLC, (Beacon) proposes to develop a 250-megawatt solar energy facility called Beacon Solar Energy Project (BSEP) in Kern County east of State Route (SR) 14. The facility would be located approximately four miles north-northwest of the northern boundary of California City, approximately 15 miles north of the Town of Mojave. The site is situated in the Fremont Valley, just east of the southernmost portion of the Sierra Nevada, in the northwestern Mojave Desert. The Fremont Valley is typified by creosote bush scrub vegetation, with patches of desert saltbush scrub, desert wash scrub, and agriculture (mostly abandoned).

The project includes the plant site (solar array, power generating equipment, support facilities, evaporation ponds, and access roads) and the project's linear facilities (transmission line, switchyard, and natural gas supply pipeline). The power block and solar arrays would occupy approximately 1,266 acres of the 2,012-acre plant site. The total area that would be fenced and subject to disturbance is 2,012 acres and includes an engineered channel, evaporation ponds, access road, administration buildings and other support facilities, and bioremediation areas. The major components of the project are described below.

Plant Site

The layout of the project's plant site includes the solar array, power block and on-site support facilities such as an administration building and warehouse. An existing dirt road off SR-14 would be paved to provide access to the solar array, power block, and support facilities on the plant site. The entire property would be fenced with low maintenance fencing (e.g. single or double strand barbed-wire fence) to prevent human access; in addition, tortoise-proof fencing would be erected around the plant site to exclude desert tortoise and deter other wildlife from entering the site (BS 2008i).

On-site facilities also would include 44 -acres of evaporation ponds to receive the waste stream from the project's water treatment and cooling water system. The evaporation ponds would feature a double liner system with a leak collection and recovery system. The ponds would have sufficiently steep slopes to deter nesting by shorebirds, with at least two feet of freeboard to prevent birds from drinking at the berm edges, and maintenance of a minimum water depth of two feet to deter use by wading birds (BS 2008i). The evaporation ponds would be designed to contain any accumulated bottom solids for the life of the project. If waste needs to be removed for pond maintenance, it would be transported off site for disposal as nonhazardous waste in accordance with applicable laws and regulations. In addition, a bioremediation area is planned in a disturbed area of the plant site to handle soil impacted by incidental leaks and spills of heat transfer fluid.

The plant site is traversed diagonally from southwest to northeast by Pine Tree Creek, a dry desert wash approximately 10,900 feet in length. The plant site would be mass graded at the beginning of construction, so the applicant proposes to re-route Pine Tree Creek and a smaller (2,150-foot) unnamed dry wash inside the eastern property boundary (BS 2008a). The re-routed wash would be outside the desert tortoise fencing but within a low maintenance security fence (DB 2008e). The newly created drainage would be a trapezoidal channel approximately 14,000 feet long with 3:1 gradient slopes and a minimum bottom width of 345 feet, spreading to a maximum of about 2,900 feet at the end of the wash (BS 2008a). Average depth of the rerouted wash would be approximately eight feet (DB 2008i).

Initial site preparation such as grading waters of the state is anticipated to take approximately 90 days at the onset of project construction (DB 2008e). Once initial work is complete, construction of the facility is anticipated to last an additional 22 months. The operation lifetime of the project is anticipated to be up to approximately 30 years (DB 2008e).

Natural Gas Pipeline

A 17.6-mile, eight-inch natural gas pipeline would be constructed to provide fuel for start-up and emergency operations. The pipeline would connect to an existing Southern California Gas pipeline in the California City area via Neuralia Road and California City Boulevard, with a 1.8-mile segment extending from Neuralia Road into the plant site along an existing distribution line and through a cleared, ruderal area (BS 2008a). Of the 1.8-mile segment, 1.3 miles is within the plant site, and the remaining 0.5 mile is between the plant site and Neuralia Road. This pipeline would be constructed within a 15- to 20-foot right-of-way, entirely within previously disturbed road shoulders and along disturbed access roads, although much of the pipeline route is immediately adjacent to native habitat (DB 2008e).

Transmission Line and Towers

Two transmission line options are being considered to interconnect the project to the existing Barren Ridge facility, Los Angeles Department of Water and Power's (LADWP's) 230-kilovolt (kV) Barren Ridge Substation, located across SR-14 southwest of the BSEP plant site. Transmission line Option 1 would involve constructing a 230-kV transmission line approximately 3.5 miles long that would run west and southwest from the power block, cross SR-14 and extend south along an expanded LADWP right-of-way, where it would tie into the existing Inyo-Rinaldi 230-kV transmission line at the existing Barren Ridge Substation. Approximately 1.6 miles of the 3.5-mile line would be within the 2,012-acre plant site boundary. The Option 1 transmission line would be installed on 36 new steel/concrete monopoles. Potential new access roads (14 feet by 1.9 miles), in addition to spur roads (averaging 12 feet by 110 feet) to 10 pole sites, also would be built under Option 1. Option 2 would involve constructing a 230-kV transmission line approximately 2.3 miles long to a new switching station to be constructed at the location where the project's transmission line first meets LADWP's existing transmission right-of-way west of SR-14. A second 230-kV transmission line of approximately one mile would then be constructed within the expanded LADWP right-of-way to the Barren Ridge Substation.

For both Option 1 and 2, approximately 1.6 miles of the transmission lines would be constructed within the 2,012-acre plant site, and both transmission lines would be installed on 36 new steel/concrete monopoles and would tie into the existing Inyo-Rinaldi 230-kV transmission line at the existing Barren Ridge Switching Station (BS 2008i). Under Option 2, however, a new electrical switchyard would be built in association with the project. The switchyard would be accessed from the existing graded patrol road that runs along the Inyo-Rinaldi Transmission line, and chain-link security fencing and desert tortoise fencing would be installed around the switchyard. Potential new access roads (14 feet by 1.0 mile), in addition to spur roads (averaging 12 feet by 110 feet) to 17 poles sites, also would be built under Option 2 (BS 2008i).

Vegetation and Wildlife

Plant Communities

Seven vegetation communities were mapped within the plant site and along linear facilities (BSE 2008a). **Biological Resources Table 2** (from BS 2008i, Table 1, p. 12) summarizes the acreage of vegetation communities within each project feature.

Biological Resources Table 2
BSEP Vegetation Communities/Cover Types

Vegetation Communities/Cover Type	Acreage
Plant Site	
Mojave Desert Wash Scrub	60.3
Developed	2.7
Fallow Agricultural-Ruderal	1,579.7
Fallow Agricultural-Disturbed Atriplex Scrub	369.2
Subtotal Plant Site	2,011.9
Transmission Line	
Mojave Creosote Bush Scrub (Option 1/Option 2)	5.0/5.8
Fallow Agricultural Ruderal	0.9
Natural Gas Pipeline	
Developed (road, road shoulder)	60.0
Subtotal Off-Site	65.9/66.7

The fallow agricultural-ruderal vegetation community covers the majority of the plant site and a portion of the transmission line alignments. This relatively barren plant community reflects the disturbance from past agricultural activities and is dominated by non-native plants such as Russian thistle (*Salsola tragus*), Sahara mustard (*Brassica tournefortii*), and Mediterranean schismus (*Schismus arabicus*). Vegetative cover is very sparse, ranging from 0 to 2 percent (BS 2008a).

Fallow agricultural-disturbed atriplex scrub is the second most common plant community at the plant site. It occupies areas previously used for agriculture but which have now been recolonized by several native atriplex shrub species. The dominant species is the allscale (*Atriplex polycarpa*), a species particularly effective at reoccupying abandoned agricultural lands. Other plants found within this vegetation community are shadscale (*Atriplex confertifolia*), Russian thistle, and salt heliotrope (*Heliotropium curassavicum*). Shrub cover in this vegetation community is approximately 22 to 25 percent (BS 2008a).

Mojave Desert wash scrub is an open shrubby community with scattered microphyllous trees and shrubs on well-drained sandy soils. This vegetation community is found in washes, arroyos, and canyons of intermittent streams throughout the Mojave Desert, and in the project area occurs within Pine Creek Tree Wash. The dominant plant in this community is the scale broom (*Lepidospartum squamatum*). Other shrubs occurring in this community are box thorn (*Lycium cooperi*), bladderpod (*Isomeris arborea*), rubber rabbitbush (*Chrysothamnus nauseosus*), bladder sage (*Salazaria mexicana*), and Mormon tea (*Ephedra nevadensis* and *E. californica*). The smaller of the two dry washes within the plant site is unvegetated (BS 2008a).

Mojave creosote bush scrub occurs along portions of the transmission line alignments west of the plant site. This is an open shrub, native plant community dominated mainly by creosote bush. Other shrubs commonly found in this vegetation community include white bursage (*Ambrosia dumosa*), box thorn, silver cholla (*Cylindropuntia echinocarpa*), and occasional Joshua trees (*Yucca brevifolia*). While dominated by shrubs (approximately 18 percent shrub cover), this vegetation community also has an herbaceous layer, which during 2008 surveys included species such as Mojave sun cups (*Camissonia campestris*), Mojave pincushion (*Chaenactis xantiana*), brittle spineflower (*Chorizanthe brevicornu*), pygmy poppy (*Eschscholzia minutiflora* ssp. *minutiflora*), California goldfields (*Lasthenia californica*), and desert dandelion (*Malacothrix glabrata*) (BS 2008i).

The areas mapped as “developed” include unpaved and paved roads and road shoulders, the rail line, canals, and areas cleared for residential uses within the plant site. This was the only cover type along the 17.6-mile natural gas pipeline right-of-way.

Sensitive Vegetation Communities

Sensitive vegetation communities are those that are considered rare in the region, support special status plant or animal species, or receive regulatory protection. No sensitive vegetation communities occur in the survey area or within one mile of project boundaries (BSE 2008a, EDAW 2008d).

Ephemeral Drainages/Waters of the State

The project site is located on the alluvial sediments of the Fremont Valley, due east of the alluvial fans emanating from the east side of the Sierra Nevada. The valley is a closed basin that contains one playa, Koehn Lake. The project area slopes gently northeast toward the lake, which is approximately six miles from the plant site. During infrequent large precipitation events, runoff from the site may reach Koehn Lake (DB 2008i).

Pine Tree Creek, a dry desert wash, traverses the site diagonally from southwest to northeast for approximately 10,900 linear feet (DB 2008i). A smaller, unnamed wash crosses the southwestern portion of the plant site from west to east and is approximately 2,150 linear feet (DB 2008i). The smaller wash is unvegetated, but Pine Tree Creek is characterized by approximately 15 percent cover of Mojave Desert wash scrub, totaling 60.3 acres (DB 2008i).

The washes occurring within the plant site have been disturbed by past agricultural activities and is occupied primarily by monotypic stands of scale broom with a limited understory composed primarily of patchy red-stem stork’s bill (*Erodium cicutarium*) and Mediterranean grass (*Schismus barbatus*). Windblown dead Russian thistle has collected in large portions of the washes. The vegetation community type of the wash, classified as southern alluvial fan scrub, is primarily restricted to floodplain habitats containing riverine cobbles, boulders, and sand. These areas flood infrequently (approximately every 5 to 10 years), so that many upland species become established in the wash (DB 2008i). The occasional flooding and sediment reworking, however, is the driving force that maintains this vegetation type (DB 2008i).

The extent and distribution of the collective area of state waters occurring within the plant site, based upon the presence of bed and bank, for Pine Tree Creek is 14.96 acres and 1.04 acres for the unnamed wash (DB 2008i). Of the total 16.00 acres of state waters, the extent and distribution of scale-broom occurring within Pine Tree Creek is 2.4 acres. The remaining 13.60 acres of state waters are riverine unconsolidated bottom (i.e., unvegetated waters of the state). No wetlands occur within or near the project area (BSE 2008a).

The U.S. Army Corps of Engineers issued an approved jurisdictional determination for the BSEP on February 5, 2008, concluding that drainages on the plant site are not jurisdictional waters of the U.S. because they were tributaries to a non-navigable waterway, Koehn Lake (BSE 2008a, Appendix F.2).

Wildlife

The plant site and most of the proposed linear facility alignments are disturbed and sparsely vegetated, but nevertheless support a diversity of wildlife species. Reptiles detected during the 2007/2008 surveys include desert tortoise (*Gopherus agassizii*), side-blotched lizard (*Uta stansburiana*), long-nosed leopard lizard (Gambelia wislizenii), western whiptail (*Cnemidophorus tigris*), zebra-tailed lizard (*Callisaurus draconoides*) red coachwhip (*Masticophis flagellum piceus*), pacific gopher snake (*Pituophis catenifer*), and Mohave green rattlesnake (*Crotalus scutulatus scutulatus*). Mammals recorded during the surveys include desert cottontail (*Sylvilagus audubonii*), black-tailed jackrabbit (*Lepus californicus*), whitetail antelope squirrel (*Ammospermophilus leucurus*), and coyote (*Canis latrans*). Desert kit fox sign (*Vulpes macrotis macrotis*) was also detected during the surveys (BSE 2008a, EDAW 2008d).

The project area provides forage, cover, roosting, and nesting habitat for a variety of bird species, despite the relatively low vegetative cover and a history of agricultural disturbance. Some of the resident and migratory birds detected in and near the BSEP site in 2007 and/or 2008 surveys include common poorwill (*Phalaenoptilus nuttallii*), lesser nighthawk (*Chordeiles acutipennis*), greater roadrunner (*Geococcyx californianus*), long-billed curlew (*Numenius americanus*), black-crowned night heron (*Nycticorax nycticorax*), mourning dove (*Zenaida macroura*), black-throated sparrow (*Amphispiza bilineata*), white-crowned sparrow (*Zonotrichia leucophrys*), sage sparrow (*Amphispiza belli*), horned lark (*Eremophila alpestris*), verdin (*Auriparus flaviceps*), California thrasher (*Toxostoma redivivum*), Le Conte’s thrasher (*Toxostoma lecontei*), and loggerhead shrike (*Lanius ludovicianus*). Resident raptors detected at the site include burrowing owl (*Athene cunicularia*) and American kestrel (*Falco sparverius*). Red-tailed hawk (*Buteo jamaicensis*) and peregrine falcon (*Falco peregrinus*) were also detected (BSE 2008a, EDAW 2008d).

Special-Status Species

Biological Resources Table 3 lists special-status species that are known to occur or could potentially occur in the project area and vicinity. None of the rare plant species listed below was detected during the 2007 and 2008 surveys (BSE 2008a, EDAW 2008d). Floristic surveys were repeated in 2008 because 2007 surveys occurred during a dry year when many of the target plant species might not be blooming. Conditions during the 2008 surveys were adequate for determining the presence/absence of the rare plant species listed below (EDAW 2008d). Seven special status wildlife species were detected during the surveys and are discussed in more detail below. Species observed during the 2007/2008 surveys are indicated by **bold-face type.**

Biological Resources Table 3
Special-Status Species Known or Potentially Occurring in the BSEP Area

PLANTS		
Common Name	***Scientific Name***	**Status State/Fed/CNPS**
Alkali mariposa lily	*Calochortus striatus*	__/__/1B.2
Red Rock tarplant	*Deinandra arida*	R/__/1B.2
Mojave tarplant	*Deinandra mohavensis*	E/__/1B.3
Red Rock poppy	*Eschscholzia minutiflora ssp.twisselmannii*	__/__/ 1B.2
Creamy blazing star	*Mentzelia tridentata*	__/__/ 1B.3
Charlotte's phacelia	*Phacelia nashiana*	__/__/ 1B.2

WILDLIFE		
Common Name	***Scientific Name***	**Status State/Federal**
Reptiles		
Desert tortoise	***Gopherus agassizii***	**ST/FT**
Birds		
Burrowing owl	***Athene cunicularia***	**CSC/BCC**
American peregrine falcon	***Falco peregrinus anatum***	**SFP/__**
Northern harrier	**Circus cyaneus**	**CSC/__**
California horned lark	***Eremophila alpestris actia***	**WL/__**
Loggerhead shrike	***Lanius ludovicianus***	**CSC/BCC**
Le Conte's thrasher	***Toxostoma lecontei***	**WL/BCC**
Mammals		
Pallid bat	*Antrozous pallidus*	CSC/__
Spotted bat	*Euderma maculatum*	CSC/__
Mohave ground squirrel	*Spermophilus mohavensis*	T/__
American badger	*Taxidea taxus*	CSC/__

Sources: CDFG 2008; CDFG 2008a

Status Codes:

Federal:
FE - Federally listed, endangered: species in danger of extinction throughout a significant portion of its range
FT - Federally listed, threatened: species likely to become endangered within the foreseeable future
BCC: Fish and Wildlife Service: Birds of Conservation Concern: Identifies migratory and non-migratory bird species (beyond those already designated as federally threatened or endangered) that represent highest conservation priorities <www.fws.gov/migratorybirds/reports/BCC2002.pdf>

State
CSC = California Species of Special Concern. Species of concern to CDFG because of declining population levels, limited ranges, and/or continuing threats have made them vulnerable to extinction.
SE - State listed as endangered
ST = State listed as threatened
R = State listed as rare.
SFP = Fully protected
WL = Watch List: includes species formerly on California Species of Special Concern List (Remsen 1978) but which did not meet the criteria for the current list of special concern bird species (Shuford and Gardali 2008).

California Native Plant Society
List 1B - Rare, threatened, or endangered in California and elsewhere
List 2 - Rare, threatened, or endangered in California but more common elsewhere
List 3 - Plants which need more information
List 4 - Limited distribution – a watch list
0.1 - Seriously threatened in California (high degree/immediacy of threat)
0.2 - Fairly threatened in California (moderate degree/immediacy of threat)
0.3 - Not very threatened in California (low degree/immediacy of threats or no current threats known)

Desert Tortoise

The desert tortoise's range includes the Mojave Desert region of Nevada, southern California, and the southwest corner of Utah and the Sonoran Desert region of Arizona and northern Mexico. The desert tortoise range is divided into Mojave and Sonoran populations. The desert tortoise in the vicinity of the BSEP is part of the Mojave population, which is primarily found in creosote bush-dominated valleys with adequate annual forbs for forage.

Desert tortoise activity is seasonally variable, and in California, peak adult and juvenile activity typically coincides with the greatest annual forage availability during the early spring and summer. However, tortoises will emerge from their burrows at any time of year when the weather is suitable. Hatchling desert tortoises typically become active earlier than adults do, and their greatest activity period can be expected between late winter and spring. During active periods, tortoises feed on a wide variety of herbaceous plants, including cactus, grasses, and annual flowers (USFWS 1994).

Annual home ranges have been estimated between 10 and 450 acres and are age, sex, seasonal, and resource density dependent, with some overlap between individuals (USFWS 1994). More than 1.5 square miles of habitat may be required to meet the life history needs of a tortoise, and individuals have been known to travel as much or more than 7 miles at a time (BLM 2001). In drought years, tortoises can be expected to wander farther in search of forage. During their active period, desert tortoises retreat to shallow burrows and aboveground shade to escape the heat of the day and will also retire to burrows at nighttime. Desert tortoises are primarily dormant in winter in underground burrows and sometimes congregate in communal dens.

Desert tortoise populations have declined throughout their range because of loss and degradation of habitat caused by urbanization, agricultural development, military training, recreational use, mining, and livestock grazing. The loss of individual desert tortoises to increased predation by common ravens, collection by humans for pets or consumption, collisions with vehicles on paved and unpaved roads, and mortality resulting from diseases also contributed to declines (USFWS 2004).

Survey Results for Desert Tortoise

Protocol level surveys conducted in 2007 and 2008 provided 100 percent survey coverage of the plant site and linear facilities and surrounding buffer area (BS 2008a, EDAW 2008d). A total of seven desert tortoises were observed during the biological surveys in 2008, all outside the plant site boundary (BS 2008i). Four of the seven tortoises were observed west of SR-14. Two were north of the plant site and east of the railroad tracks, and one was observed in the 1,000-foot Zone of Influence transect north of California City Boulevard. In addition, two carcasses were observed, one in the Zone-of-Influence near the gas pipeline route along Neuralia Road, approximately 4 miles north of California City, and the other carcass was observed on the west side of SR-14 (BS 2008i).

No live desert tortoises were found within the plant site boundary during the 2007 and 2008 protocol level surveys. Desert tortoise sign detected within these boundaries include an intact juvenile carcass that had been depredated by a raven and a deteriorated adult burrow (BS 2008i). In addition, two other sets of old (greater than four years since death) bone and carapace fragments were found near the southern edge of the plant site boundary. The 2008 survey documented two live desert tortoises north of the plant site and east of the railroad tracks, one associated with a burrow. Following the 2007 surveys, another juvenile desert tortoise carcass, also preyed upon by a raven, was observed during subsequent work at the site. In addition, one live adult desert tortoise was also detected on the northwestern edge of the plant site boundary, along the main access road, and was likely a transient from adjacent habitat (EDAW 2008d, 2008a).

Desert Tortoise Habitat in the Project Area

The 2,012-acre plant site provides little or no habitat to support resident desert tortoise because these former agricultural lands are either barren or shrub cover is less than 2 percent (BS 2008i). This assessment is based on a detailed field evaluation by Dr. Alice Karl, a recognized expert on the species, and is supported by the survey findings. Approximately 369 acres of the plant site is occupied by fallow agricultural-disturbed atriplex scrub, where shrubs are regrowing in a monotypic stand of allscale with patchy shrub cover interspersed with broad barren swathes, and another 60 acres is vegetated by Mojave Desert wash scrub. In the disturbed atriplex scrub the soils are fine and slightly hard, with poor friability, making them unsuitable for desert tortoise to dig burrows. The scattered patches of vegetation are separated by barren areas up to 0.5 miles in extent. Dispersal across these barren areas is highly unlikely, and such large barren areas would not be included within a desert tortoise's home range.

Transient desert tortoise might occasionally occur in these atriplex shrub patches or in the 60.3 acres of vegetated desert wash that crosses the plant site. However, the presence of transient desert tortoises in this poor habitat would likely be attributable to the proximity of the adjoining native habitat outside of the plant site rather than reflecting use by resident individuals (BS 2008i). The Mojave creosote bush scrub north of the plant site is poor-to-fair quality desert tortoise habitat because it has also been disrupted by past farming activities (BS 2008i); therefore, desert tortoise densities are expected to be low in this area. Furthermore, desert tortoises have been excluded for decades from much of the plant site by a chicken wire perimeter fence originally built to exclude rabbits from the agricultural fields (BS 2008i). Long segments of this fence are intact, blocking desert tortoise from entering the site.

Desert washes often provide movement corridors for desert tortoise and other wildlife, but the desert wash on this site is unlikely to provide a connection between suitable desert tortoise habitats. The portion of Pine Tree Creek wash that is revegetating consists of a patch on the northwest side of the plant site, bounded on the east and south by large barren areas, and therefore does not lead to suitable habitat. The wash is characterized by low shrub diversity and discontinuous vegetative cover (EDAW 2008b). This wash is mostly bordered by barren land, and its northern terminus is dominated by stands of the non-native Russian thistle. The wash also transitions from moderately suitable habitat south of the project to non-habitat in the northeast within and adjacent to the plant site. These factors strongly suggest that desert tortoises are not using the wash as a movement corridor.

Desert Tortoise Critical Habitat/Desert Tortoise Natural Areas

The plant site is located approximately 3 miles west of the Desert Tortoise Natural Area (DTNA), approximately 1 mile south of the Jawbone/Butterbredt Area of Critical Environmental Concern (ACEC), and approximately 7 miles west of federally designated desert tortoise critical habitat (BS 2008a).

Mohave Ground Squirrel

The Mohave ground squirrel is rare throughout its range and is restricted to the Mojave Desert in San Bernardino, Los Angeles, Kern, and Inyo counties. This species inhabits desert areas, including alluvial fans, basins, and plains with deep sandy or gravelly friable soils with an abundance of native herbaceous vegetation. Mohave ground squirrels can be found in Mojave creosote bush scrub, shadscale desert scrub, alkali scrub, and Joshua tree woodland. This species feeds on green vegetation and seeds but may also eat carrion (BS 2008a).

This diurnal ground squirrel is active above ground in the spring and early summer. Emergence dates vary from March to June, depending on elevation. Squirrels begin aestivation in July or August. Stored body fat is the principal source of energy for aestivation, although food is also stored in the burrows. Home range size averages approximately 0.91 acres and varies from 0.25 to 2 acres.

Populations of Mohave ground squirrel have been diminished by urban development, off-road vehicle use, and agriculture. The Mohave ground squirrel is threatened by loss of habitat and degradation of habitat due to urban, suburban, and rural development; agriculture; military activities; energy development; livestock grazing; and off-highway vehicle use.

Mohave Ground Squirrel Habitat/Presence in the Project Area

Protocol surveys were not conducted for Mohave ground squirrel, and instead the evaluation of potential presence of this species was based on two habitat assessments conducted in 2007 by Dr. Phil Leitner, a recognized expert on Mohave ground squirrel. Dr. Leitner also evaluated relevant published and unpublished data.

Dr. Leitner notes that an extensive area of Mojave creosote bush scrub immediately adjoins the plant site to the east and south, and this habitat provides suitable habitat for the Mohave ground squirrel (BS 2008i). However, the plant site itself provides little to no habitat for this species. Approximately 430 acres of the 2,012-acre plant site supports scattered perennial vegetation; the remaining area is essentially barren, reflecting past agricultural disturbance (BS 2008i). The 429.5 acres of the plant site with some perennial plant cover would not support a resident population of Mohave ground squirrel because essential food resources are absent. This species will eat saltbush foliage and is known to consume small amounts of the two non-native herbs present on the site, red-stemmed filaree and Mediterranean grass, but individuals cannot maintain themselves on a diet composed only of only these plants (BS 2008i). Based on Dr. Lietner's experience and those of other Mohave ground squirrel experts whom he queried, Dr. Lietner concluded that monotypic saltbush scrub such as that found in the northwest portion of the BSEP plant site would not support a resident population of Mohave ground squirrel (BS 2008i).

Dr. Lietner also concluded that Pine Tree Creek wash is unsuitable for resident Mohave ground squirrel because the shrub vegetation is sparse (with barren stretches extending as much as 1,875 feet), plant diversity is low, and there is little cover or forage appropriate for the species (BS 2008i). He also concluded that the plant site has no value as a movement corridor for this species; dispersing juveniles might attempt to enter the plant site from adjoining creosote bush habitat to the west, south, or east, but they would not cross the wide bands of barren fallow agricultural land (BS 2008i). This conclusion is based his research in the Coso area of Inyo County showing that a small playa appeared to act as a complete barrier to the dispersal movements of radio-collared juveniles (Harris and Leitner 2005). There is no evidence indicating that this species would attempt to traverse extensive areas without cover (BS 2008i). However, even disturbed agricultural lands can support annual plant species cover and provide foraging habitat during high rainfall years.

The only vegetation community in the project area capable of supporting resident populations of Mohave ground squirrel is the Mojave Creosote Bush Scrub west of SR-14. This area is located on a large alluvial fan deposited by outflows from Pine Tree Canyon. The dominant shrub species are creosote bush and white bursage. Desert senna (*Senna armata*) and cheesebush (*Hymenoclea salsola*) are also abundant, reflecting disturbance from periodic surface water flows. Vegetation surveys did not reveal the presence of winter fat (*Krascheninnikovia lanata*) or spiny hop sage (*Grayia spinosa*), two shrubs that provide important food resources for Mohave ground squirrel (Leitner and Leitner 1998). This relatively undisturbed habitat has moderately diverse vegetation that could provide adequate forage and cover for Mohave ground squirrel. The habitat on this portion of the survey area appears suitable for the species but is not of high quality (BS 2008a).

Based on this information the applicant has concluded that Mohave ground squirrel has little potential to occur within the plant site because suitable habitat is absent (BS 2008i). However, this species is assumed to be present west of SR-14, in the vicinity of the proposed transmission lines (BS 2008i).

American Badger

American badgers were once fairly widespread throughout open grassland habitats of California. They are now uncommon, permanent residents throughout most of the state, with the exception of the northern North Coast area. Known to occur in the Mojave Desert, they are most abundant in the drier open stages of most shrub, forest, and herbaceous habitats with friable soils. In the southwest, badgers are typically associated with Mojave Creosote Bush Scrub and sagebrush. Mating occurs in late summer or early fall and two to three young are born 183 to 265 days later in March or April (Long 1973). Badgers are fossorial, digging large burrows in dry, friable soils and will use multiple dens/cover burrows within their home range. They typically use a different den every day, although they can use a den for a few days at a time (Sullivan 1996). Cover burrows are an average of 30 feet in length and are approximately 3 feet in depth. Natal dens are larger and more complex than cover dens. In undisturbed, high-quality habitat, badger dens can average 0.64 dens per acre, but are much lower in highly disturbed areas (Sullivan 1996).

No American badgers were detected during project surveys in 2007 or 2008, although the California Natural Diversity Data Base (CNDDB) indicates an occurrence approximately 1 mile east of the project site (BS 2008a). The project site provides only marginal habitat for this species.

Spotted Bat

Spotted bats occur throughout western North America, and have been found from below sea level to 9,000 feet in arid, low desert habitats to high elevation conifer forests (WBWG 2005). Prominent rock features appear to be a necessary feature for roosting; roost sites are cracks, crevices, and caves, usually high in fractured rock cliffs (WBWG 2005). Spotted bats feed primarily on moths and are apparently solitary but occasionally roost or hibernate in small groups (WBWG 2005). This species is infrequently captured, although in the southwest spotted bats have been most often captured over water (WBWG 2005).

No spotted bats were observed during the surveys, but no surveys were specifically conducted for this species or any other bats. Spotted bats were recorded in 1997 in Red Rock Canyon State Park near a desert spring in canyonlands (CNDDB 2008). Staff considers it unlikely that spotted bats inhabit the BSEP because of the low vegetative cover, high levels of disturbance, and absence of water features or rocky roost sites that might attract this species.

Pallid Bat

Pallid bats range throughout western North America, inhabiting low elevation rocky arid deserts and canyonlands, shrub-steppe grasslands and higher elevation coniferous forests (WBWG 2005a). They are most abundant in xeric ecosystems, including the Great Basin, Mojave, and Sonoran deserts. This species can be a solitary rooster, or can occupy small or large roost groups; day and night roosts include crevices in rocky outcrops and cliffs, caves, mines, hollow trees or bark, and various human structures such as bridges, barns, porches, bat boxes, and human-occupied as well as vacant buildings (WBWG 2005a). Pallid bats are opportunistic generalists that glean a variety of arthropod prey from surfaces, but also capture insects on the wing (WBWG 2008a).

No pallid bats were observed during the surveys, but no surveys were specifically conducted for this species or any other bats. Pallid bats were recorded in 1997 in Red Rock Canyon State Park near an active maternity colony in a mine shaft in the vicinity of a desert spring (CNDDB 2008). Staff considers it unlikely that pallid bats inhabit the BSEP because of the low vegetative cover, high levels of disturbance, and absence of water features and suitable roosting sites.

Western Burrowing Owl

Western burrowing owls inhabit arid lands throughout much of the western United States and southern interior of western Canada (Haug et al. 1993). In the Mojave

Desert region, and in many other areas, this species has declined because of habitat modification, poisoning of its prey, and introduced nest predators. The burrowing owl is diurnal and usually non-migratory in this portion of its range.

Burrowing owls are unique among the North American owls in that they nest and roost in abandoned burrows, especially those created by California ground squirrels, kit fox, desert tortoise, and other wildlife. Burrowing owls have a strong affinity for previously occupied nesting and wintering habitats. They often return to burrows used in previous years, especially if they were successful at reproducing there in previous years (Gervais et al. 2008). The southern California breeding season (defined as from pair bonding to fledging) generally occurs from February to August with peak breeding activity from April through July (Haug et al. 1993).

In the Mojave Desert, burrowing owls generally occur at low densities in scattered populations, but they can be found in much higher densities near agricultural lands where rodent and insect prey tend to be more abundant (Gervais et al. 2008). Burrowing owls tend to be opportunistic feeders. Large arthropods, mainly beetles and grasshoppers, comprise a large portion of their diet. Small mammals, especially mice and voles (*Microtus*, *Peromyscus*, and *Mus* spp.), are also important food items. Other prey animals include reptiles and amphibians, young cottontail rabbits, bats, and birds, such as sparrows and horned larks. Consumption of insects increases during the breeding season (Haug et al. 1993).

Habitat within the project site and the one-mile buffer is suitable for burrowing owls, and in 2007 a total of 27 burrows with burrowing owl sign were identified within the survey area one-mile buffer (BS 2008a). Two burrowing owls were detected within the plant site boundary during the 2007 surveys, in association with four active burrowing owl burrows (ENSR 2008). It is likely that the owls observed in 2007 represent two pairs of owls occupying areas within the plant site boundary. Four owls (assumed to be four pairs) were detected in the buffer area surrounding the plant site and along the linear project features (ENSR 2008).

Two burrowing owls were observed outside the plant site boundary during the 2008 surveys, one within the 1,000-foot buffer at the southwest end of the natural gas pipeline corridor, next to a burrow (DB 2008d). The other burrowing owl was incidentally observed southeast of the plant site, off of an access road used by the survey team. Although one active burrowing owl burrow was documented within the 80-acre addition to the plant site, the majority of the other 7 active and 13 inactive/potential burrowing owl burrows documented during the 2008 surveys were located within the 1,000-foot buffer associated with the natural gas pipeline corridor. However, owls were not observed at any of these other burrows during the 2008 focused surveys (DB 2008d).

American peregrine falcon

Peregrine falcons are uncommon breeding residents and migrants in California, nesting near wetlands, lakes, rivers, or other water on high cliffs. They hunt for birds by swooping from flight onto flying prey. One peregrine falcon was observed perched on a utility pole at the eastern border of the survey area during May 2007 surveys. The project site provides no nesting sites for this species and limited foraging opportunities, although the proposed evaporation ponds might attract species that would be prey for peregrine falcons.

Northern harrier

Northern harriers breed in open wetlands, including marshy meadows, wet lightly grazed pastures, old fields, freshwater and brackish marshes, and dry uplands including upland prairies, mesic grasslands, drained marshlands, croplands, cold desert shrub-steppe, and riparian woodland. The densest populations of northern harriers are typically associated with large tracts of undisturbed habitat dominated by thick vegetation growth (Macwhirter and Bildstein 1996). Harrier prey includes small and medium-sized mammals (primarily rodents), birds, reptiles, and frogs.

Within eastern Kern County, the northern harrier is present year-round, but the population fluctuates due to seasonal migration and rarely breeds within the eastern portion of the county (Morlan 2008). However, annual breeding activity has been documented in the vicinity of the town of Cantil, approximately 4 miles northeast of the BSEP site (Morlan 2008). Nesting typically occurs in close proximity to marsh habitat or otherwise routinely saturated areas, including active alfalfa fields.

Two northern harriers were detected in the 1-mile survey buffer to the northeast of the plant site boundary in May 2007 (DB 2008d). This species is known to regularly nest in the vicinity of Cantil, but the absence of observations within the plant site or along any of the linear components of the project during the 2007 and 2008 surveys suggests that the project area provides only low-quality foraging habitat for the species. The project site and linear facilities do not provide suitable nesting habitat for this species, although northern harriers might rarely forage there.

Loggerhead Shrike

Loggerhead shrikes are uncommon residents throughout most of the southern portion of their range, including southern California. In southern California they are generally much more common in interior desert regions than along the coast (Humple 2008). In the Mojave Desert this species appears to be most numerous in flat or gently sloping deserts and desert/scrub edges, especially along the eastern slopes of mountainous areas (Humple 2008). Loggerhead shrikes initiate their breeding season in February and may continue with raising a second brood as late as July; they often re-nest if their first nest fails or to raise a second brood (Yosef 1996).

This species can be found within lowland, open habitat types, including creosote scrub and other desert habitats, sage scrub, non-native grasslands, chaparral, riparian, croplands, and areas characterized by open scattered trees and shrubs. Fences, posts, or other potential perches are typically present. In general, loggerhead shrikes prey upon large insects, small birds, amphibians, reptiles, and small rodents over open ground within areas of short vegetation, usually impaling prey on thorns, wire barbs, or sharp twigs to cache for later feeding (Yosef 1996).

Loggerhead shrikes are relatively common in eastern Kern County and are typically associated with open desert, Joshua tree woodland, and parks, and populations are thought to be stable or even increasing in eastern Kern County (Morlan 2008).Suitable habitat for loggerhead shrike occurs throughout the scrub habitats within the project survey area and loggerhead shrikes were observed frequently during the 2007/2008 surveys (BS 2008a, EDAW 2008d).

Le Conte's Thrasher

This species inhabits some of the hottest and driest habitats in the arid southwest, including the Mojave Desert where they occur year-round. Preferred habitats include sparse desert scrub, alkali desert scrub, and desert succulent scrub habitats with open desert washes. They seek gentle to rolling slopes bisected by dry desert washes, conditions found on alluvial fans that are found in the project area. The Le Conte's thrasher population densities are among the lowest of passerine (perching) birds, estimated at less than five birds per square kilometer in optimal habitats (Fitton 2008). This low population density decreases the probability of their detection during field surveys. This species requires areas with an accumulated leaf litter under most plants as cover for its preferred arthropod prey; it also feeds on seeds, insects, small lizards, and other small vertebrates.

Two LeConte's thrashers were observed in the eastern portion of the survey area, and one individual was observed in the 1-mile buffer southwest of the survey area during the May 2007 surveys (BS 2008). They are year-round residents at the BSEP site and use the site for nesting, foraging, and cover.

California horned lark

Horned larks prefer areas with sparse vegetation and exposed soil. In western North America, this species is associated with desert brushlands, grasslands, and similar open habitats, as well as alpine meadows (Garrett and Dunn 1981). Throughout their range, horned larks avoid all habitats dominated by dense vegetation and become scarce and locally distributed in heavily forested areas.

Multiple individuals of this species were observed frequently throughout the survey area and within the 1-mile buffer within barren areas during the 2007 and 2008 surveys (BS 2008a, EDAW 2008d).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHODS AND THRESHOLD FOR DETERMINING SIGNIFICANCE

The determination of whether a project has a significant effect on biological resources is based on the best scientific and factual data that staff could review for the project. Significance criteria are defined in the general context of the California Environmental Quality Act (CEQA) and other relevant federal and state laws, ordinances, regulations, and standards. In this analysis the following impacts to biological resources are considered significant:

- substantial adverse effects to plant species considered by the CNPS, CDFG, or USFWS to be rare, threatened, or endangered in California or with strict habitat requirements and narrow distributions; substantial impact to a sensitive natural community (i.e., community that is especially diverse; regionally uncommon; or of special concern to local, state, and federal agencies);

- substantial adverse effects to wildlife species that are federally listed or state-listed or proposed to be listed; a substantial impact to wildlife species of special concern to CDFG, candidates for state listing, or animals fully protected in California;
- substantial adverse effects on habitats that serve as breeding, foraging, nesting, or migrating grounds and are limited in availability or that serve as core habitats for regional plant and wildlife populations; and
- substantial adverse effect on important riparian habitats or wetlands and any other "Waters of the U.S." or state jurisdictional waters.

Direct and Indirect Impacts and Mitigation

The California Environmental Quality Act Guidelines define direct impacts as those impacts that result from the project and occur at the same time and place. Indirect impacts are caused by the project, but can occur later in time or farther removed in distance while still reasonably foreseeable and related to the project. The potential impacts discussed in this analysis are those most likely to be associated with construction and operation of the project.

Impact analyses typically characterize effects to plant communities as temporary or permanent, with a permanent impact referring to areas that are paved or otherwise precluded from restoration to a pre-project state. In the Mojave Desert ecosystem, the definition of permanent impacts needs to reflect the slow recovery rates of its plant communities. Natural recovery rates from disturbance in these systems depend on the nature and severity of the impact. For example, creosote shrubs can resprout a full canopy within five years after damage from heavy vehicle traffic (Gibson et al. 2004), but more severe damage involving vegetation removal and soil disturbance can take from 50 to 300 years; complete ecosystem recovery may require more than 3,000 years (Lovich and Bainbridge 1999). In this analysis, an impact is considered temporary only if there is evidence to indicate that pre-disturbance levels of biomass, cover, density, community structure, and soil characteristics could be achieved within five years.

Biological Resources Table 4 summarizes the impacts to biological resources resulting from BSEP construction and operation.

Biological Resources Table 4
Summary of Impact/Mitigation

Biological Resource	Impact/Mitigation
Mojave Desert Plant Communities & Wildlife Habitat	**Impacts:** Permanent loss of 2,012-acres of marginal wildlife habitat, including 430 acres of disturbed vegetation; potential direct impacts to terrestrial wildlife by heavy equipment and grading; increased risk of roadkill; increased disturbance/dust to nearby vegetation and wildlife; spread of non-native invasive weeds. **Mitigation**: Avoidance and minimization measures (**BIO-1 - BIO 8**); off-site habitat acquisition and enhancement (**BIO-11**); implement Best Management Practices **(BIO-12)**

Biological Resource	Impact/Mitigation
Waters of the State	**Impacts:** Impacts to 10,900 feet of Pine Tree Creek and 2,150 feet of an unnamed desert wash, resulting in permanent loss of 60.3 acres of Desert Wash Shrub and 16 acres of waters of the state; loss of associated hydrological and biological functions. **Mitigation**: Replace functions and values of impacted desert wash with a new channel that incorporates native desert wash vegetation (**BIO-18**).
Special-Status Wildlife	
Desert tortoise	**Impact:** Potential take of transient individuals; permanent loss of 430 acres of poor quality (Fallow Atriplex Scrub, Desert Wash Scrub) habitat on the plant site and 5 -5.8 acres of Mohave Creosote Scrub habitat occupied by desert tortoise; increased risk of predation from ravens and other predators; increased road kill hazard from construction and operations traffic. **Mitigation**: Avoidance and minimization measures (**BIO-9, BIO-12)**; off-site habitat acquisition, endowment, and enhancement of 115 – 117.4 acres (**BIO-11**); raven management plan (**BIO-13).**
Mohave ground squirrel	**Impact:** Potential take of transient individuals; permanent loss of 430 acres of poor quality (Fallow Atriplex Scrub, Desert Wash Scrub) habitat on the plant site and 5 – 5.8 acres of Mohave Creosote Scrub habitat occupied by Mohave ground squirrels; increased risk of disturbance to nearby populations; increased road kill hazard from construction and operations traffic. **Mitigation**: Avoidance and minimization measures (**BIO-1** through **BIO-8, BIO-12**); off-site habitat acquisition, endowment, and enhancement of 115 – 117.4 acres (**BIO-11**).
American badger	**Impact:** Potential loss and fragmentation of habitat, loss of foraging grounds, crushing or entombing of animals during construction. **Mitigation**: Conduct pre-construction surveys and implement avoidance measures (**BIO-12)**.
Western burrowing owl	**Impact**: Potential loss of nest, eggs, or young; loss of breeding and foraging habitat on the plant site; disturbance of nesting and foraging activities for populations on and near the plant site and linear facilities. **Mitigation**: Implement burrowing owl impact avoidance and mitigation measures; passive relocation, off-site habitat acquisition and enhancement of 20 acres (**BIO 16)**.
Other Special-Status Birds • Loggerhead shrike • California horned lark • Le Conte's thrasher	**Impact**: Disturbance of nesting activities, potential loss of nest, eggs, or young; loss of breeding and foraging habitat. **Mitigation**: Conduct pre-construction nesting surveys, implement avoidance measures (**BIO-16**); off-site habitat acquisition and enhancement (**BIO-11**).

Overview of Impacts to Vegetation and Wildlife

Grading of the entire 2,012-acre BSEP plant site would not impact sensitive plant communities or rare plants, but would directly affect wildlife by removal of shrubs and herbaceous vegetation, resulting in loss and fragmentation of cover, breeding, and foraging habitat. During construction, wildlife could be crushed or entombed in dens or burrows and could collide with vehicles. Much of the plant site is barren or sparsely vegetated, but nevertheless supports a diversity of mammals, birds, and reptiles, including some special-status wildlife species. Construction on the plant site would permanently eliminate 60.3 acres of Mojave desert wash scrub, 369.2 acres of fallow agricultural-disturbed atriplex Scrub, and 1,579.7 acres of fallow agricultural ruderal (BS 2008a).

Construction of a transmission line and spur access roads west of SR-14 would result in permanent impacts to 5.0 acres (5.8 acres under Option 2) of Mojave creosote bush scrub. These impact calculations include permanent impacts resulting from construction of access roads, pole pads, and pull/splicing sites. All of these transmission line construction activities would occur in occupied desert tortoise and Mohave ground squirrel habitat; potential impacts to these listed species and proposed mitigation measures are discussed in detail below.

The 17.6-mile gas pipeline would be trenched in the disturbed road shoulder, affecting approximately 60 acres of ruderal lands, but would not affect directly native plant communities. Even in ruderal areas, construction and trenching pose some risk to wildlife, including disturbance to nesting birds and trapping wildlife in open trenches. Desert tortoise and burrowing owls could occur in the vicinity of the gas pipeline alignment; potential impacts to these species are discussed in more detail below.

Direct construction impacts to vegetation and wildlife could be reduced to less than significant levels with implementation of impact avoidance and minimization measures described in staff's proposed Conditions of Certification **BIO-1** through **BIO-8** and in other conditions of certification.

Vegetation Impacts

Impacts to plant communities are summarized in **Biological Resources Table 5**. No rare plants or sensitive plant communities would be directly impacted by the proposed project. Indirect impacts to native plant communities are discussed below.

Biological Resources Table 5
Impacts to Vegetation Communities BSEP

Vegetation Communities/Cover Type	Impact Area (acres)
Mojave Desert Wash Scrub	60.3
Developed	62.7
Fallow Agricultural-Ruderal	1,580.6
Fallow Agricultural-Disturbed Atriplex Scrub	369.2
Mojave Creosote Bush Scrub (Option 1/Option 2)	5.0/5.8

Spread of Noxious Weeds

Construction activities and soil disturbance could introduce new noxious weeds to lands adjacent to the BSEP plant site and its linear facilities and could further spread weeds already present in the project vicinity. The spread of invasive plants is a major threat to biological resources in the Mojave Desert because non-native plants can displace native plants, increase the threat of wildfire, and supplant wildlife foods that are important to desert tortoise and other herbivorous species. The applicant has proposed a variety of weed control measures such as establishing weed wash stations for construction vehicles and using only weed-free products for erosion control. Staff has incorporated these recommendations into staff's proposed Condition of Certification **BIO-8**. Implementation of this condition would reduce potential impacts from introduction and spread of noxious weeds to less-than-significant levels.

Dust

Disturbance of the soil's surface caused by construction traffic and other activities would result in increased wind erosion of the soil. Aeolian transport of dust and sand can result in the degradation of soil and vegetation over a widening area (Okin et al. 2001). Dust can have deleterious physiological effects on plants and may affect their productivity and nutritional qualities. The destruction of plants and soil crusts by windblown sand and dust exacerbates the erodibility of the soil and accelerates the loss of nutrients (Okin et al. 2001). Soil erosion from construction activities and vehicle activity, which affects vegetation and soil properties, could have an adverse effect on both tortoise and Mohave ground squirrel foraging and burrowing potential. The impacts of increased dust and other construction impacts can be minimized with implementation of staff's proposed Condition of Certification **BIO-8** and with staff's proposed Conditions of Certification **SOIL&WATER-1** and **-2**.

Impacts to Waters of the State

Grading and construction would impact approximately 10,900 linear feet (14.96 acres of state waters) of Pine Tree Creek and approximately 2,150 linear feet (1.04 acres of state waters) of the unnamed wash. Approximately 2,990 linear feet and 2.40 acres of these state waters are vegetated with southern alluvial fan scrub dominated by scale-broom. The remaining 10,060 linear feet and 13.60 acres are unvegetated. Permanent loss of 16 acres of jurisdictional state waters and 13,050 linear feet of desert wash is considered a significant impact according to CEQA guidelines.

Alternatives to Impacting Waters

In their June 19, 2008 comment letter on BSEP, the CDFG recommended avoiding impacts to state waters and requested that the applicant evaluate alternative site layouts that would avoid the desert washes (CDFG 2008b). The applicant's response (CEC 2008uu) indicated that avoiding the washes would be infeasible because the plant site does not offer sufficient space to locate the project entirely on one side of the wash or the other, requiring splitting the project into two uneven portions that would straddle the wash. This split would require multiple crossings of the wash for roads and pipes (heat transfer fluid and gas), resulting in major disruption of the wash during construction and significantly changing the nature of the wash. The applicant also pointed out that the split layout would shift the power block significantly off-center of the field, resulting in operational problems, longer plant start-ups, lower annual energy production, and overall higher cost of electricity. Furthermore, without modifications to the washes, the applicant thought this layout would expose large portions of the solar field to flooding, creating difficulties for operations and insurance liability. Staff believes the applicant should revisit their analysis and conclusions regarding the infeasibility of avoiding the desert washes and evaluate an alternative layout as described in the **Alternatives** section.

Applicant's Proposal for Mitigation for Impacts to Waters of the State

The applicant proposes to mitigate the loss of the two desert washes by replacing the functions and values of the impacted drainages with a diversion channel at the southern and eastern perimeter of the site. The new channel would be a trapezoidal drainage approximately 14,000 feet long with 3:1 gradient side slopes (BS 2008g). The minimum bottom width would be 345 feet with a maximum of about 2,900 feet at the downstream end of the channel (BS 2880g). The average depth of the proposed diversion channel would be approximately 8 feet, with earthen bottom and banks and riprap reinforcement only in areas prone to erosion (BS 2008g). The applicant proposes to use the low flow channel created within this broad floodway would provide the site for mitigation and revegetation to replace the biological functions of the recreated wash (BS 2008i).

The applicant provided a conceptual mitigation plan in its Streambed Alteration Agreement application submitted to the CDFG (BS 2008i), with some subsequent modifications (BS 2008g). The conceptual mitigation plan calls for a 1:1 replacement ratio for permanent impacts to 13.6 acres of unvegetated waters of the state and a 2: 1 replacement ratio for impacts to 2.4 acres of vegetated wash (BS 2008g). The 18.4-acre mitigation area would be located in the center of the approximately 80-acre diversion channel (BS 2008g). The width of the mitigation area is expected to range from 40 to 70 feet with an average width of approximately 60 feet (BS 2008g). The applicant proposes a goal of achieving 26 percent vegetated cover within the 18.4-acre mitigation area (4.8 acres) by creating physical conditions to promote natural successional processes and native plant recruitment within the mitigation area. To develop the appropriate physical conditions, the applicant proposed a conceptual mitigation that would involve contour grading in the rerouted wash mitigation area to establish a meandering low flow channel and microtopographic variation; hand-seeding native alluvial fan scrub species over a 4.8 acres area in the rerouted wash, non-native weed control; and monitoring and maintenance for a minimum of five years.

Staff requested additional information to supplement the conceptual mitigation plan, including a description of success criteria to evaluate whether the diversion channel replaced the biological values, water conveyance/flood control functions of the impacted wash, and identification of remedial measures if success criteria were not met. The applicant provided the following hydrological and biological success criteria to augment the conceptual mitigation plan and described corrective actions to be taken if success criteria were not met (DB 2008r):

Hydrological Success Criteria

Goal: Creation of a drainage system with physical characteristics of a natural desert wash (interfluves, shelving, scour areas, and sediment deposition areas) and retention of the existing hydrology that will support dynamic channel formation processes and resulting functions.

- Flood flow, volume, and extent are equivalent to or better than existing wash. *Objective*: Minimal or no structures or diversions, and maintain natural water sources and flood flow, volume, and extent.

- Maintain hydrologic connections are equivalent to or better than existing wash. *Objective*: Maintain natural water sources and confirm the on-site wash segment remains properly connected with the upstream and downstream channel segments.
- Sediment transport is equivalent to or better than existing wash. *Objective*: Maintain natural levels of sediment transport by maintaining natural flood-prone area width, and prevent development of significant erosion areas. Creation of interfluves, shelving, and sediment deposition that results in a braided system would provide evidence of this condition.

Biological Success Criteria

Goal: Creation of a drainage system with biological functions and values (botanical and wildlife) of a natural desert wash system.

- Achieve vegetation cover equivalent to or better than existing wash. *Objective*: Restore and maintain vegetation to support functional wildlife habitat by obtaining 26 percent vegetation cover within the wash area.
- Achieve plant species richness, evenness, and structure equivalent to or better than reference site. *Objective*: As part of the mitigation plan, the applicant proposes a minimum five-year maintenance and monitoring program to evaluate the success of the restoration/mitigation effort. Maintenance and monitoring for the restoration effort would include evaluation of vegetative cover, structure, and composition, and physical characteristics of the restoration area, removal of invasive nonnative species, erosion control, and trash removal.

Corrective Actions/Maintenance

If the success criteria described above are not being met, the applicant proposed a variety of remedial actions, including extending the monitoring period, additional seeding, invasive weed control, additional minor grading or contouring, and addition of organic material or rocks to promote microtopographic complexity.

In addition to the five years of monitoring and the evaluation of success criteria for achieving mitigation goals, the applicant proposed maintenance of the rerouted wash for the life of the project to ensure structural stability and effective flow conveyance. Maintenance inspection and repair activities for the re-routed wash, including the slopes and level spreader discharge point, are anticipated to include structural inspections, erosion control repairs, and debris removal.

Off-Site Mitigation

In addition to the restoration efforts on the re-routed desert wash, the applicant also proposed finding compensation lands that would include desert washes as well as provide habitat for listed species (BS 2008g). The applicant will be seeking appropriate acreage and locations of habitat that would be purchased and preserved off-site to provide mitigation for desert tortoise, Mohave ground squirrel, and western burrowing owl. The applicant anticipates that these off-site compensation lands may have desert wash features associated with them that will serve as additional mitigation for on-site impacts to jurisdictional state waters above and beyond the on-site mitigation described previously.

Staff's Response to Applicant's Mitigation Proposal

The following discussion is based on the assumption that the applicant has convincingly demonstrated the infeasibility of developing an alternative project layout that would avoid impacting desert washes. Under those circumstances staff would support the applicant's basic goals of replicating natural hydrological and biological functions and values in the engineered wash. However, staff does not concur with the specific goal of revegetating an 18.4-acre mitigation area to create 26 percent vegetative cover within the low flow channel. The hydraulic modeling and geomorphic assessment described in the **Soil & Water** section indicates that the current design of proposed drainage will result in lateral migration and down-cutting of the channel, and that the channel will migrate towards and erode bank toes of the engineered slopes. These anticipated conditions, with an unstable, downcutting, and migrating channel, would not sustain the micro-contouring and seeding of native vegetation proposed by the applicant. Furthermore, staff does not accept the premise that establishing 18.4 acres of vegetated cover or any specific acreage of vegetation replaces the biological functions of the existing wash. To replicate those functions and values the engineered wash must instead create hydrologic and geomorphologic conditions that would promote natural successional processes and native plant recruitment.

In the **Soil & Water** section, Energy Commission staff recommends that the applicant re-evaluate the proposed channel design and also develop a channel stabilization plan based on the establishment of stable slopes to reduce floodwater velocities and thus erosion potential. Staff made further recommendations that channel stabilization plans incorporate bioengineering solutions where appropriate. Bioengineering solutions achieve stability by incorporating live vegetation with structural materials, such as combining deep-rooted vegetation with rock. The vegetation eventually strengthens the bank at the surface by increasing roughness and reducing shear stress and also reinforces the subsurface with the root matrix. Rock or concrete armoring would also be needed to protect the channel in areas with high shear stresses and velocities. The new analysis conducted by the applicant will determine which areas would need hard armoring and which would support bioengineering. Staff believes that incorporating native vegetation where appropriate into the channel stabilization plan would enhance establishment and recruitment of native vegetation in the new channel, would provide habitat for wildlife, and would minimize and offset the significant impacts associated with loss of state waters.

Staff believes that maintenance and monitoring for any bioengineering or revegetation efforts must extend for the life of the project rather than for five years. Staff considers a five-year interval insufficient to achieve the objectives of the mitigation, to evaluate the success of the revegetation-mitigation effort, and to integrate the required channel maintenance (erosion control repairs and debris removal) with protection of biological resources.

Staff is recommending this extended monitoring and maintenance period because infrequent storm events are likely to control the hydrological and biological features of this re-created ecosystem, and five years falls short of an appropriate interval to evaluate the effect of such storm events on revegetation efforts. Lichvar et al. (2006) describes "ordinary" events that define bed and bank limits of channels of the arid southwestern U.S. as typically corresponding to the five- to eight-year event, as opposed to the one- and two-year event in temperate climates (USACE 2007). Furthermore, no one can accurately predict the extent of erosion control repairs and debris/sediment removal that might be needed for this artificial channel over the next few decades. Such maintenance activities might adversely affect revegetation efforts without an active monitoring program in place that would safeguard and maintain the mitigation site for the life of the project. The CDFG and the Energy Commission staffs must also have opportunities to work with the applicant in developing adaptive management measures to address unanticipated setbacks to the revegetation efforts. The ongoing maintenance and monitoring would provide the framework for such adaptive management. Finally, the scale and scope of the applicant's proposed attempt to recreate a Mojave Desert natural desert wash ecosystem is unprecedented; the uncertainty of a successful outcome dictates that active monitoring, maintenance, and adaptive management take place over the life of the project.

Staff has incorporated the basic elements of the applicant's proposed conceptual mitigation plan and hydrological/biological success criteria and objectives into staff's proposed Condition of Certification **BIO-18**. Staff concurs with the direction provided in the **Soil & Water** section, which recommends the applicant re-evaluate the channel design and create a channel stabilization plan that includes bioengineering solutions. Staff's proposed Condition of Certification **BIO-18** further requires that a final mitigation plan be prepared in consultation with CDFG, Energy Commission staff, and appropriate experts (revegetation specialist, engineer, geomorphologist, hydrologist) that would provide adequate detail for implementation, maintenance, and monitoring. This condition also includes the requirement that monitoring and maintenance continue for the life of the project. This condition further specifies that the applicant secure off-site mitigation lands that include washes similar to those impacted by the project.

With implementation of staff's proposed Condition of Certification **BIO-18**, impacts to 16.0 acres of state waters and loss of the hydrological and biological functions of the project site desert washes would be mitigated to less-than-significant levels. This condition also fulfills requirements of CDFG's Lake and Streambed Alteration Agreement program pursuant to California Fish and Game Code section 1600 et seq.

Impacts to Migratory/Special-Status Bird Species

Vegetation at the plant site and along linear facilities provides foraging, cover, and/or breeding habitat for migratory birds, including a number of special-status bird species confirmed to be present at the site. Loggerhead shrike, LeConte's thrasher, and California horned lark are special-status species known to breed and forage at the site. Western burrowing owls, which also occur at the BSEP plant site and linear facilities, are discussed below. Power plant construction would eliminate nesting habitat for these and other species and could result in direct and cumulative impacts to these species due to habitat loss or injury/fatality of individuals. No impacts to northern harrier or peregrine falcon are anticipated because these species occur only infrequently at the BSEP area and do not breed there.

The loss of active bird nests or young is regulated by the federal Migratory Bird Treaty Act and Fish and Game Code section 3503. The applicant has proposed mitigation measures to avoid and minimize impacts to nesting birds that have been incorporated into staff's proposed Conditions of Certification **BIO-8** (Impact Avoidance and Best Management Practices) and **BIO-15** (Pre-Construction Nest Surveys). Implementation of staff's proposed conditions of certification would avoid direct impacts to nests, eggs, or young of migratory birds and would minimize the impacts of construction disturbance to nesting birds to less-than-significant levels.

Loss of nesting and foraging habitat for these special-status bird species would add to the cumulative, significant loss of habitat for these species within the region. Implementation of staff's proposed Condition of Certification **BIO-11**, the compensatory mitigation plan, would offset this habitat loss to less-than-significant levels.

Impacts to Burrowing Owls

Burrowing owls, a state species of special concern, nest on the project site and could be directly impacted by construction of the BSEP. Without implementation of impact avoidance and minimization measures, burrowing owl adults, eggs, or young could be crushed or entombed by grading activities, and nesting and foraging activities would be directly and indirectly impacted by construction and operation of the project. The project would also result in permanent loss of 2,012 acres that are currently used by burrowing owls for nesting and foraging. Staff considers these impacts significant.

To avoid potential impacts to burrowing owls that might be nesting or residing within burrows in the project impact area, the applicant has proposed conducting pre-constructions surveys on the plant site and along all linear facilities, using methods recommended by CDFG (California Burrowing Owl Consortium 1993). To avoid direct take of owls and offset potentially significant impacts to nesting or resident owls, the applicant has proposed passive relocation.

Passive relocation involves encouraging owls to move from occupied burrows to alternate natural or artificial burrows that are at least 150 feet from the impact zone and that are within or contiguous to a minimum of 6.5 acres of foraging habitat for each pair of relocated owls (CDFG 1995). Passive relocation of owls is only implemented during the non-breeding season (CDFG 1995) in order to avoid egg and dependent chick separation from adult owls, which would likely result in death of those eggs and young.

Passive relocation for the owls occurring on the BSEP site would involve encouraging the movement of on-site burrowing owls to a 14.39-acre parcel owned by the applicant and located just outside of the plant site boundary, east of SR-14, and north of the facility access road (DB 2008n). To facilitate the passive relocation, a total of four artificial burrows would be constructed within an approximately 6-acre portion of this 14.39-acre parcel prior to clearing and grading on the BSEP plant site. The proposed relocation area is characterized by Mojave creosote scrub habitat and currently provides suitable habitat for burrowing owls (BS 2008g). The applicant proposes to monitor the translocation sites for up to five years after initiation of passive relocation.

Passive relocation, construction of artificial burrows, and surveys prior to relocation would be in accordance with CDFG-approved guidelines (California Burrowing Owl Consortium 1993). The applicant would conduct ongoing maintenance and monitoring of the conservation area for exotic weed control for a five-year period following construction of the burrows (BS 2008g). The applicant has also agreed to find a third-party beneficiary conservation organization acceptable to CDFG and the Energy Commission to establish a conservation easement for management of the approximately 6-acre portion (the portion containing the artificial burrows) of the 14.39-acre relocation parcel (BS 2008h, p. BR-5).

In addition to the potential direct impacts to nesting burrows, the BSEP would permanently eliminate a large expanse of habitat on the plant site that is currently available for foraging and breeding by burrowing owls. Habitat loss is one of the primary threats to California's burrowing owl population (Gervais et al. 2008), and the BSEP project would contribute incrementally to this significant loss. To offset this loss, the applicant has proposed acquisition and protection of 20 acres of land suitable for burrowing owls at some off-site location yet to be determined (BS 2008g). This off-site acquisition of 20 acres would serve to compensate for loss of foraging and breeding habitat for two burrowing owl pairs, and would be in addition to the permanent protection of 6 acres within the 14.39 acre relocation parcel near the project site.

Staff concurs with the applicant's proposed impact avoidance, minimization, and mitigation measures, and has incorporated them into staff's proposed Condition of Certification **BIO-17**. With implementation of this condition, potential impacts to burrowing owls would be reduced to less-than-significant levels.

Noise

Noise from construction activities could temporarily discourage wildlife from foraging and nesting immediately adjacent to the project area. Many bird species rely on vocalizations during the breeding season to attract a mate within their territory, and noise from construction could disturb nesting birds and other wildlife and adversely affect nesting and other activities.

As discussed in the **Noise** section of this Preliminary Staff Analysis, a maximum noise level of 75 dBA Ldn is estimated to occur at a distance of 50 feet from the acoustic center of the construction activity (most often the power block) and attenuate to 40 dBA Ldn or less at project site boundaries. Assuming that construction noise for this project would be relatively constant, the 40 dBA Ldn estimated for construction noise would therefore equate to 34 dBA Leq at site boundaries, similar to levels of ambient noise.

The loudest noise likely to occur with BSEP construction is created by steam blows, an activity needed after construction to clear 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. Steam blows can produce noise as loud as 130 dBA at a distance of 100 feet. In order to minimize disturbance from steam blows, the steam blow piping can be equipped with a silencer that would reduce noise levels by 20 to 30 dBA. Staff's proposed Conditions of Certification **NOISE-6** and **NOISE-8** require that any high pressure steam blows be muffled with an appropriate silencer. Based on the analysis described in the **Noise** section, staff concludes that noise impacts to nesting birds and other wildlife would be less than significant.

Impacts to Special-Status Mammals

Mohave Ground Squirrel

Most of the 2,012-acre plant site is not likely to be inhabited by the Mohave ground squirrel because it is barren, lacking perennial and herbaceous vegetation that would provide appropriate forage and cover for this species. The 429.5 acres of disturbed vegetation (fallow atriplex scrub and desert wash scrub) on the plant site would also not support resident Mohave ground squirrel because it lacks the appropriate variety of native shrub and herbaceous plants needed for sustenance throughout the active season (BS 2008i). The 60.3 acres of desert wash on the site also does not provide suitable habitat or a movement corridor for Mohave ground squirrels because shrub vegetation is sparse, plant diversity is low and little cover or forage appropriate for the species is available (BS 2008i). However, occasionally transient individuals might occupy this disturbed vegetation, accessing it from the Mojave creosote bush scrub vegetation to the west.

The applicant's Mohave ground squirrel expert, Dr. Philip Leitner, suggests that a reasonable estimate of transient use of this vegetated area might be two individuals, based on his knowledge of this species' habitats and published and unpublished studies (BS 2008i). He estimates that grading and construction within the plant site might result in the incidental take of up to two transient Mohave ground squirrels that could occasionally enter these disturbed and degraded lands. Staff has reviewed the analysis by Dr. Leitner and the studies he cites supporting his conclusions, and while acknowledging that such estimates are necessarily speculative, agrees that loss of two transient individuals is a reasonable estimate of take of Mohave ground squirrel during construction within the plant site.

Unlike the habitat on the plant site, the Mojave creosote bush scrub west of SR-14 supports relatively undisturbed habitat with moderately diverse vegetation that could provide adequate forage and cover for a resident population of Mohave ground squirrel (BS 2008i). Construction activities within this area for installation of the proposed 230-kV transmission line could result in take of Mohave ground squirrels by vehicle strikes or burial in burrows and would also result in permanent impacts to their habitat. The habitat loss would amount to 5 acres of habitat loss for Option 1 and 5.8 acres for Option 2.

The applicant proposes to acquire and enhance 115 acres (117.4 acres for Option 2) to compensate for the potential take of two individuals during construction on the plant site and for permanent habitat loss of 5.0 acres (5.8 acres for Option 2) of Mojave creosote bush scrub (BS 2008i). The applicant's rationale for this acreage rests on the assumption that enhancement of mitigation lands would increase carrying capacity for this species, compensating for the loss of individuals and loss of habitat (BS 2008i). Staff agrees with the applicant's analysis and proposed compensatory mitigation and has incorporated the applicant's impact avoidance, minimization, and compensation measures into staff's proposed Conditions of Certification **BIO-11** and **BIO-12**. Implementation of these conditions would reduce impacts to Mohave ground squirrel to less-than-significant levels and would also satisfy the California Department of Fish and Game's requirements under section 2081 of California's Fish and Game Code.

Impacts to American Badger and Desert Kit Fox

American badgers were not detected on the BSEP site, but the site includes marginally suitable foraging and denning habitat for this species. The American badger is protected under Title 14, California Code of Regulations (sections 670.2 and 670.5), and potential impacts to individuals of this species must be mitigated to less-than-significant levels. Construction of the BSEP project could kill or injure American badgers by crushing with heavy equipment or could entomb them within a den. Construction activities could also result in disturbance or harassment of individuals. Staff's proposed Condition of Certification **BIO-16** requires that concurrent with the desert tortoise clearance survey, a qualified biologist perform a preconstruction survey for badger dens in the project area, including areas within 250 feet of all project facilities, utility corridors, and access roads.

The desert kit fox (*Vulpes macrotis*) is not a special-status species, but it is protected under Title 14, California Code of Regulations (sections 670.2 and 670.5), and potential impacts to individuals of this species must be avoided (CDFG 2008b). Desert kit fox sign were detected on the BSEP site, and the site includes marginally suitable foraging and denning habitat for this species. Construction of the BSEP project could kill or injure desert kit fox by crushing with heavy equipment, or could entomb them within a den if avoidance measures are not implemented. Construction activities could also result in disturbance or harassment of individuals. Staff's proposed Condition of Certification **BIO-16** requires that concurrent with the desert tortoise clearance survey, a qualified biologist perform a preconstruction survey for kit fox dens in the project area, including areas within 250 feet of all project facilities, utility corridors, and access roads.

Impacts to Desert Tortoise

Protocol level surveys conducted in 2007 and 2008 indicate that no resident population of desert tortoise inhabits the 2,012-acre plant site because it is highly disturbed by past agricultural operations and is mostly barren, lacking perennial and herbaceous vegetation that would provide appropriate forage and burrow sites for this species (BS2008i, EDAW 2008d). The 60.3 acres of desert wash on the site also does not provide suitable habitat or a movement corridor for desert tortoise because shrub vegetation is sparse, plant diversity is low, and little cover or forage appropriate for the species is available (BS 2008i). However, occasionally transient individuals might occur within the 429.5 acre portion of the plant site that supports disturbed fallow atriplex scrub and desert wash scrub. Desert tortoise could access this habitat from the Mojave creosote bush scrub vegetation to the west (BS 2008i).

Unlike the habitat on the plant site, the Mojave creosote bush scrub west of SR-14 supports relatively undisturbed habitat with moderately diverse vegetation that could provide adequate forage and cover for a resident population of desert tortoise (BS 2008a, BS 2008i). Construction activities within this area for installation of the proposed 230-kV transmission line could result in permanent loss of 5 acres of habitat loss for Option 1 and 5.8 acres for Option 2 (BS 2008i). During construction in this area, along the gas pipeline and in vegetated portions of the plant site, desert tortoise could be harmed during clearing, grading, and trenching activities or might become entrapped within open trenches and pipes.

Construction activities could also result in direct mortality, injury, or harassment of individuals as a result of encounters with vehicles or heavy equipment. Other direct effects could include individual tortoise being crushed or entombed in their burrows, collection or vandalism, disruption of tortoise behavior during construction or operation of facilities, disturbance by noise or vibrations from the heavy equipment, and injury or mortality from encounters with workers' or visitors' pets. Desert tortoise may also be attracted to the construction area by application of water to control dust, placing them at higher risk of injury or mortality. Increased human activity and vehicle travel would occur from the construction and improvement of access roads, which could disturb, injure, or kill individual tortoises. Also, tortoise may take shelter under parked vehicles and be killed, injured, or harassed when the vehicles are moved.

After construction is complete, additional project-related impacts (increased levels of predation on young tortoise from increased raven numbers, increased levels of disturbance and incidence of vehicle strikes) could continue to adversely affect desert tortoise. These potential operations impacts are discussed in more detail later in this subsection.

The applicant has recommended impact avoidance and minimization measures to reduce construction impacts to desert tortoise, including installation of exclusion fencing to keep desert tortoise out of construction areas, reducing construction traffic and speed limits to reduce the incidence of road kills, worker training programs, and other measures. Staff has incorporated these recommendations into conditions of certification. These include staff's proposed Conditions of Certification **BIO-1** through **BIO-8**, which apply to protection of desert tortoise and other biological resources in and near the BSEP. Staff's proposed Condition of Certification **BIO-9** would involve installation of security and desert tortoise exclusionary fencing around the entire project site, and **BIO-11** requires verification that all desert tortoise avoidance, minimization, and compensation measures have been implemented.

Construction of a desert tortoise exclusion fence at the perimeter of the plant site also has potential to adversely affect desert tortoise. The CDFG expressed concerns about impacts to resident tortoises if they are segregated from their home range with a fence, or if transient individuals engage in "fence-walking" to try to pass through the fence (Vance 2008). Such behavior might result in increased exposure to predation and increased levels of stress. Staff consulted with the applicant's desert tortoise expert, Dr. Alice Karl, to assess the potential for this impact to be a potential contributor to the impacts of the BSEP (Karl 2008).

Dr. Karl said that fence-walking typically occurs when a tortoise is moved out of its home range; often, it is when a tortoise is trying to return home. It may also occur when a tortoise is fenced out of part of its typical use area. While there have not been any quantitative scientific studies of this behavior of which Dr. Karl is aware, it has been observed with captive tortoises with the Fort Irwin relocation, during the Hyundai test track translocation activities, and by other researchers (Karl 2008). Dr. Karl thought fence-walking was very unlikely at BSEP because the plant site is not within the home range of any desert tortoise, given the lack of habitat and absence of records of any live tortoises within the plant site during the 2007/2008 surveys. Furthermore, based on her experience and conversations with other researchers, even if this behavior did occur, it would be short-lived and intermittent.

The applicant has proposed acquisition of off-site habitat to compensate for possible incidental take of up to two transient desert tortoises and for habitat loss along the transmission line corridors. The applicant proposes to acquire and enhance 115 acres (117.4 acres for Option 2) to compensate for the potential take of two individual desert tortoises during construction on the plant site and for permanent habitat loss of 5.0 acres (5.8 acres for Option 2) of Mojave creosote bush scrub (BS 2008i). As with the Mohave ground squirrel compensatory mitigation, the applicant's rationale for this acreage rests on the assumption that enhancement of mitigation lands would increase carrying capacity for this species, compensating for the loss of individuals and loss of habitat (BS 2008i).

Staff agrees with the applicant's analysis and proposed compensatory mitigation and has incorporated the applicant's impact avoidance, minimization, and compensation measures into staff's proposed Conditions of Certification **BIO-9** through **BIO-12**. Implementation of these conditions would reduce impacts to desert tortoise to less-than-significant levels and would also satisfy the California Department of Fish and Game's requirements under section 2081 of California's Fish and Game Code.

Operation Impacts and Mitigation

Potential operation impacts to biological resources include increased risk of raven predation on desert tortoise and wildlife, impacts to birds due to hazardous conditions at the evaporation ponds, increased levels of traffic and disturbance, potential collisions with structures, and lighting. These impacts are discussed below.

Ravens

Construction and operation of the BSEP project area could provide new sources of food, water, and nesting sites that might draw unnaturally high numbers of tortoise predators such as the common raven. Ravens depend on human encroachment to expand into areas where they were previously absent or in low abundance. Ravens habituate to human activities and are subsidized by the food and water, as well as roosting and nesting resources that are introduced or augmented by human encroachment. Common raven populations in some areas of the Mojave Desert have increased 1,500 percent from 1968 to 1988 in response to expanding human use of the desert (Boarman 2003). Since ravens were scarce in this area prior to 1940, the current level of raven predation on juvenile desert tortoises is considered to be an unnatural occurrence (BLM 1990).

Construction and operation of the BSEP would provide new attractants and subsidies that might result in changes in raven population or behavior, which could subsequently affect the desert tortoise population in the region by increased predation. The applicant has identified these raven attractants and subsidies as follows:

- water from evaporation ponds;
- potential creation of new perching/roosting/nesting sites;

- water ponding from dust suppression; and
- construction/operation waste management.

The potential impacts to desert tortoise populations and other species resulting from operation of the BSEP's evaporation ponds are discussed later in this subsection. Impacts and mitigation for the remaining three factors are discussed below.

Perching, Roosting, and Nesting Sites. Most raven predation on desert tortoise is thought to take place during the spring, most likely by breeding birds that have been shown to spend most of their time foraging within 1,300 feet of their nests (Kristan and Boarman 2003). Therefore, BSEP structures such as towers, transmission poles and lines, and maintenance buildings that offer new nesting substrates may pose increased risk of predation to nearby desert tortoise populations. The applicant has proposed project design features to reduce raven nesting and includes physical deterrents to nesting such as bird spikes and nest removal and monitoring to make sure these design features work as intended. These measures are described in more detail in staff's proposed Condition of Certification **BIO-13**, the raven monitoring and management plan.

Ponding. During construction, water would be applied to the graded areas, construction right-of-way, dirt roads, trenches, spoil piles, and other areas of ground disturbance to minimize dust emissions and topsoil erosion. Ponding water resulting from these dust suppression activities has the potential to attract ravens, thereby potentially resulting in increased desert tortoise predation. As described in Condition of Certification **BIO-8**, this potential impact would be minimized by using the minimal amount of water needed for dust abatement, with a Biological Monitor patrolling the construction sites to ensure water does not puddle.

Food Waste. Ravens are scavengers that forage at landfills, dumpsters behind restaurants and grocery stores, open garbage drums and plastic bags placed on the curb for garbage pickup, and on roadkill. Both the construction and operation phases of the BSEP would result in increased waste generation in the project area, and improper management of food waste could attract ravens. This potential impact could be avoided with implementation of measures described in staff's proposed Condition of Certification **BIO-8**, which requires that all food-related waste be placed in self-closing containers and removed daily from the site, and that food not be left unattended on the site.

Cumulative/Regional Impacts of Ravens

Construction and operation of the BSEP and subsequent increases in raven predation could contribute incrementally to the cumulative significant impacts to the Mojave Desert population of desert tortoise. The BSEP area is already subject to elevated raven predation pressure and any cumulative loss of juvenile tortoise due to the further addition of raven subsidies could have a long-term effect on the regional tortoise population by reducing the recruitment of juvenile tortoises into the adult life stages (Boarman 2003). The effects of this shortage may not be apparent for years because tortoises do not typically reach sexual maturity until approximately 15 to 20 years of age.

The applicant has been working closely with staff, USFWS, and the CDFG since May 2008 to develop measures that address potential cumulative impacts. As part of its efforts to proactively address the issue of raven monitoring and management, the applicant has submitted two draft raven monitoring and mitigation plans (DB 2008h). The first of these plans, which was submitted in July 2008, provided a detailed monitoring program to assess the contributions of the BSEP to the regional raven cumulative impacts and take appropriate action if raven numbers exceeded a certain threshold. The applicant revised this approach with its second raven plan submittal in October 2008 (EDAW 2008c).

This second draft plan responded to a request by the USFWS that the applicant address raven monitoring and management on a more regional basis; the USFWS is currently developing a comprehensive, regional raven management plan that would implement recommendations in the USFWS *Environmental Assessment to Implement a Desert Tortoise Recovery Plan Task: Reduce Common Raven Predation on the Desert Tortoise* (USFWS 2008b).

To comply with the USFWS request that the BSEP be integrated into this regional approach, the applicant replaced the proposed regional monitoring with payment of an in-lieu fee to a third party account set up by the USFWS to support a regional monitoring plan (Blackford 2009). The applicant is in the process of making final revisions to its October 2008 raven management/monitoring plan to address specific comments from USFWS on impact avoidance and minimization measures, and to finalize arrangements for the in-lieu fee payment for regional management (Blackford 2009, USFWS 2009). These fees would contribute to a region-wide management and monitoring program in the California Desert Conservation Area, and would replace the offsite raven monitoring program originally proposed by the applicant (USFWS 2009). Staff's proposed Condition of Certification **BIO-13** specifies that the applicant complete a final Raven Management and Monitoring Plan in consultation with staff, CDFG, and USFWS. Staff anticipates that the applicant will be able to produce a final raven monitoring and management plan that will meet the approval of CDFG, USFWS and staff well before publication of the Final Staff Assessment. The in-lieu fee will offset contributions of the project to cumulative impacts associated with regional increases in raven numbers, and the project-specific raven management efforts proposed by the applicant will reduce impacts to desert tortoise from raven predation to less-than-significant levels.

Other Predators

In addition to ravens, feral dogs have emerged as significant predators of the tortoise. Dogs may range several miles into the desert and have been found digging up and killing desert tortoises (USFWS 1994; Evans 2001). Dogs brought to the project site with visitors may harass, injure, or kill desert tortoises, particularly if allowed off leash to roam freely in occupied desert tortoise habitat. Condition of Certification **BIO-6**, the worker environmental awareness training, and restrictions on pets being brought to the site required of all personnel (Condition of Certification **BIO-8**) would reduce the potential for these impacts.

Impacts of Evaporation Ponds

The BSEP would include three evaporation ponds that would collect blowdown water from the cooling towers. The applicant originally proposed three ponds with a nominal surface area of 8.3 acres each for a total of 25 acres (BS 2008a). However, some preliminary calculations re-evaluating evaporation rates and the amount of blowdown water produced during project operation indicates that the proposed pond design is too small and would need to be a minimum of 44 acres (see **Soils & Water** section Appendix A for more information).

Staff, CDFG, and USFWS are concerned about the wildlife threats posed by the evaporation ponds. First, creation of a new water source to an area where water is scarce would attract ravens to the BSEP, potentially increasing predation rates on juvenile desert tortoise in adjacent habitat. Second, waterfowl, shorebirds, and other resident or migratory birds that drink or forage at the ponds might be harmed by selenium or hyper-saline conditions resulting from high total-dissolved-solids concentrations. Monitoring results from the summer of 2007 at nearby Harper Lake Solar Electric Generating System revealed numerous waterfowl deaths at the evaporation ponds due to salt toxicosis (DB 2008r). The Harper Lake ponds, which are approximately 30 miles from the BSEP, are similar to those proposed by the applicant. Although Harper Lake is near a wetland area and therefore attracts species unlikely to occur regularly at BSEP, the evaporation ponds and associated risk to birds are a source of significant concern.

The applicant has addressed these concerns by proposing project design features for the evaporation ponds that would discourage bird use. The operational design of the ponds would include a minimum water depth of 2 feet to prevent shorebirds and waders from using the ponds, and a minimum freeboard of 2 feet so ravens would be unable to reach the water at the pond’s edge (EDAW 2008c). In addition, the interior sides of the ponds would be at a 33 percent slope (3:1, horizontal:vertical), too steep to accommodate ravens or shorebirds at the sides of the pond. Waterfowl, however, could still land directly on the water regardless of side slopes. Other features to discourage bird use include the use of anti-perching devices and bird deterrents placed strategically along the perimeter of the ponds to exclude ravens and other birds from accessing the edge of the ponds to drink water (DB 2008r). Air canons could also be used if birds continued to use the ponds despite these deterrence measures (DB 2008o). The air canons would be used only if the birds are not nesting; use of air canons after nest establishment can increase activity levels and elevate the energy needs of the birds, increasing feeding in potentially harmful waters of the evaporation ponds.

In the course of several data responses (DB 2008r, DB 2008o, DB 2008d, and DB 2008n), the applicant also discussed additional deterrence measures and a monitoring program to evaluate bird use at the ponds and assess water quality, depth, and temperature. The monitoring program described by the applicant included avian monitoring at least twice monthly for the life of the project and quarterly monitoring for selenium and TDS, as well as triggers for remedial action (hazing, managing water levels in the ponds) based on results of the monitoring.

The **Soil & Water** and **Alternatives** sections discuss a dry-cooling alternative that would eliminate the evaporation ponds, and would therefore eliminate the significant threat to migratory birds and desert tortoise posed by the ponds. This is the alternative preferred by staff, CDFG, and USFWS because it would entirely avoid the impact. However, if this alternative is not adopted and evaporation ponds are to be part of BSEP, staff concurs with the project design features for the ponds and with the basic elements of the proposed monitoring program and deterrence features. Staff requests that that the applicant compile the information that is currently scattered in the data responses into a single comprehensive draft Evaporation Pond Design, Monitoring, and Management Plan. This draft plan, which should incorporate any revisions to pond size or design based on the staff's analysis in the **Soils & Waters** section, will need review and approval by USFWS, CDFG and staff. Once approved, the plan can be incorporated into staff's proposed Condition of Certification **BIO-14**. If appropriately designed, implementation of this plan could reduce evaporation pond impacts to birds to less-than-significant levels.

Increased Risk from Roads/Traffic

Vehicle traffic would increase as a result of BSEP construction and improvement of access roads, increasing the risk of injuring or killing desert tortoise and other wildlife. Construction of the BSEP would be completed over a period of approximately 25 months, with a peak at Month 15 of approximately 836 workers per day (BS 2008a, p. 5.13-11). The average would be approximately 440 workers over the course of construction (BS 2008a, p. 5.13-11). Construction is also forecast to generate an average of approximately 15 to 20 one-way truck trips per day with a peak of approximately 75 truck trips per day. During operations approximately 38 truck trips per month are expected, the estimate of vehicular traffic from 66 workers (BS 2008a, p. 5.13-15).

The potential for increased traffic-related tortoise mortality is greatest along paved roads where vehicle frequency and speed is greatest, although tortoises on dirt roads may also be affected depending on vehicle frequency and speed. Census data indicate that desert tortoise numbers decline as vehicle use increases and that tortoise sign increases with increased distance from roads (Nicholson 1978).

To minimize the risks of increased traffic fatality and other hazards associated with roads at the BSEP project site, the applicant has proposed a variety of impact minimization measures which staff has incorporated into staff's proposed Condition of Certification **BIO-8**. These measures include confining vehicular traffic to and from the project site to existing routes of travel, prohibiting cross country vehicle and equipment use outside designated work areas, and imposing a speed limit of 25 miles per hour on routes within desert tortoise habitat.

Bird Collisions and Electrocution

Birds are known to collide with communications towers, transmission lines, and other elevated structures. The tallest structures at the plant site would be the steam turbine generator, which would be 55 feet tall. The power block, cooling tower, and other structures would be 50 feet or less in height. These structures at the BSEP site would be unlikely to pose a collision risk because they are shorter than those typically associated with bird collision events and because bird densities are already low in the project area and would be even lower after the solar fields are built and no habitat is available to attract birds.

Large raptors like golden eagles can be electrocuted by transmission lines when a bird's wings simultaneously contact two conductors of different phases, or a conductor and a ground. This happens most frequently when a bird attempts to perch on a structure with insufficient clearance between these elements. The presence of distribution lines 69-kV or less represents more of a danger to raptors than transmission lines greater than 69 kV, because the spacing between elements in distribution lines is much less than that of transmission lines (APLIC 1996). The proposed transmission lines would be 115-kV. To minimize risk of electrocution, the applicant has proposed a "raptor-friendly" construction design for the transmission line with conductor wire spacing greater than the wingspans of large birds to help prevent electrocution as described in *Suggested Practices for Raptor Protection on Power Lines: The State of the Art in 2006* (APLIC 2006). With the proposed mitigation addressed in staff's proposed Condition of Certification **BIO-8**, staff concludes that the proposed transmission lines would not pose a significant threat to birds.

Lighting

Lighting plays a significant role in collision risk with tall towers because lights can attract nocturnal migrant songbirds, and major bird kill events have been reported at lighted communications towers (Manville 2001) with most kills from towers higher than 300 to 500 feet (Kerlinger 2004). BSEP operations would require on-site nighttime lighting for safety and security, which could disturb nocturnal wildlife. To reduce off-site lighting impacts, lighting at the BSEP facility would be restricted to areas required for safety, security, and operation. Exterior lights would be hooded, and lights would be directed on site so that light or glare would be minimized. Low-pressure sodium lamps and fixtures of a non-glare type would be specified. Switched lighting would be provided for areas where continuous lighting is not required for normal operation, safety, or security; this would allow these areas to remain un-illuminated (dark) most of the time, thereby minimizing the amount of lighting potentially visible off site. The measures are described in staff's proposed Condition of Certification **VIS-4**. With implementation of this measure, lighting at the BSEP would have no adverse effects on wildlife.
Lighting may also be required to facilitate nighttime construction activities, which might disrupt the activities and affect behavior of nocturnal wildlife. As discussed in the Visual Resources section, construction lighting must be consistent with worker safety codes, directed toward the center of the construction site, shielded to prevent light from straying offsite, and task-specific. Staff has proposed Condition of Certification **VIS-3** to formalize temporary lighting measures during construction activity and on the laydown area. With implementation of this measure, construction lighting at the BSEP would have no adverse effects on wildlife.

Noise

The primary noise sources associated with operation of the BSEP include the steam turbine generators, cooling tower, start-up boiler, and various pumps and fans. As discussed in the **Noise** analysis, power plant noise levels are predicted to be less than

40 dBA Ldn (34 dBA Leq) at all sensitive receptors during daytime operation and less than 22 dBA Lmax at night. The impact on operational noise on surrounding wildlife is expected to be less than significant.

CUMULATIVE IMPACTS

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 (Cal. Code Regs., tit. 14, § 15130). Cumulative impacts must be addressed if the incremental effect of a project, combined with the effects of other projects is “cumulatively considerable” (14 Cal. Code Regs., § 15130(a)). Such incremental effects are to be “viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects” (14 Cal. Code Regs., § 15164(b)(1)).

This cumulative impact analysis makes a broad, regional evaluation of the impacts of past projects that threaten plant and animal communities within California’s southern deserts and also discusses in a general fashion future foreseeable threats. This overview of regional impacts is followed by a more detailed discussion of the effects of past, present, and future projects to biological resources of the western Mojave Desert.

Proposed Projects

The Pine Tree Wind Development Project is a wind development project under construction located approximately 6 miles west from the BSEP. The project consists of 80 1.5-MW wind turbine generators plus eight miles of transmission line. Although this project spans an 8,000-acre area, ground disturbance will total approximately 238 acres with permanent disturbance totaling approximately 132 acres (BS 2008a). In addition to the Pine Tree Wind Development Project, the LADWP is also proposing to upgrade and build new transmission capacity from the new Barren Ridge Substation approximately 1.5 miles southwest of the BSEP site in unincorporated Kern County to the Castaic Power Plant near Lake Castaic/Santa Clarita in unincorporated Los Angeles County. A Notice of Intent was filed for the Barren Ridge project in April 2008 (*Federal Register*, April 7, 2008, Volume 73, Number 67, pp. 18734–18737), and the environmental review process for this project is in the early stages. The Barren Ridge-Castaic Transmission Project is designed to tie into LADWP’s Pine Tree Wind Development Project and to other proposed wind and solar developments (BS 2008a).

Four solar power project applications have been submitted to the U.S. Bureau of Land Management (BLM) in Kern County or just to the east of the Kern County line in San Bernardino County (BS 2008a, p. 5.1-3). These proposed projects, which are all within a 30-mile radius of the BSEP, include the following.

- Opti-Solar Sapphire Project is a proposed 6,000-acre, 745-MW photovoltaic facility that would be located approximately 12 miles southwest of the project site. It would be situated just west of SR-14 near the town of Mojave.

- The Opti-Solar Turquoise Project is a proposed 11,800-acre, 400-MW photovoltaic facility that would be located in the Little Dixie Wash area just east of SR-14. This location is approximately 15.5 miles north of the BSEP.
- Solar Millennium - Ridgecrest Project, an 11,000-acre, 1,000-MW parabolic trough facility, is proposed along Jacks Ranch Road south of Ridgecrest and approximately 28 miles northeast of the BSEP site.
- Another Solar Millennium project, a 5,000-acre, 300-MW parabolic trough facility, is proposed for a site near the intersection of Highway 395 and Cuddeback Road just inside San Bernardino County. The site is 22 miles east of the BSEP site.

Regional Overview

Over the past 200 years California's southern deserts have been subject to major human-induced changes that have threatened native plant and animal communities by habitat loss, fragmentation, and degradation. Some of the most conspicuous threats are those activities that have resulted in large-scale habitat loss due to urbanization, agricultural uses, landfills, military operations, and mining activities, as well as activities that fragment and degrade habitats such as roads, off-highway vehicle activity, recreational use, and grazing (Berry et al. 1996; Avery 1997; Jennings 1997). The introduction of non-native plant species and increases in predators such as ravens has also contributed to population declines and range contractions for many special-status plant and animal species (Boarman 2002). Against this backdrop of past projects within California's deserts, proposed wind and solar energy projects have the potential to further reduce, degrade and fragment native plant and animal populations, in particular sensitive species such as desert tortoise and Mohave ground squirrel. BLM has received solar and wind applications for use of BLM land for approximately one million acres of the California Desert Conservation Area.

In the context of this large-scale habitat loss and currently proposed projects in the region, staff assessed the potential of the BSEP project to contribute to cumulative significant loss and degradation of habitat for desert plants and wildlife, including desert tortoise, Mohave ground squirrel, and other special-status species such as burrowing owl. The BSEP plant site is highly disturbed by past agricultural activities and currently supports marginal wildlife habitat, with little potential to support resident populations of sensitive species such as desert tortoise and Mohave ground squirrel. However, transient individuals could occur in the vegetated portions of the site, and resident populations inhabit the area west of SR-14 where transmission line construction would occur. Furthermore, over the years the disturbed vegetation on the site would have continued to recover from historical disturbances and would eventually provide improved habitat for these species. The BSEP would prevent recovery of these disturbed agricultural lands and would contribute to fragmentation of native plant communities in the project area. BSEP would also contribute to the cumulative increase in ravens in the area, increasing predation pressures on desert tortoise.

Staff believes that implementation of the conditions of certification described below will minimize and offset the contributions of the BSEP to the cumulative loss of habitat for native plant communities and wildlife, including special-status species. Staff's proposed Condition of Certification **BIO-11** requires the applicant to acquire and enhance at least

115 acres of suitable habitat for desert tortoise and Mohave ground squirrel. This habitat would be connected to other suitable habitat for these species and would offset any habitat loss associated with the BSEP. Staff's proposed Condition of Certification **BIO-17** requires 20 acres of off-site habitat acquisition to be protected and managed for burrowing owls, and staff's proposed Condition of Certification **BIO-13**, the Raven Management and Monitoring Plan, specifically includes measures that would address the cumulative regional increases in raven predation on desert tortoise. Finally, Staff's proposed Condition of Certification **BIO-18** requires that the impacts to the desert washes be mitigated by re-creating natural hydrological and biological conditions in the new diversion channel, offsetting cumulative losses to waters of the state. With implementation of these conditions of certification, the BSEP project would not result in significant cumulative impacts to biological resources.

COMPLIANCE WITH LORS

The proposed project must comply with state and federal laws, ordinances, regulations, and standards (LORS) that address state and federally listed species, as well as other sensitive species and habitats, and must secure the appropriate permits to satisfy these LORS. The Energy Commission has a one-stop permitting process for all thermal power plants rated 50 MW or more under the Warren-Alquist Act (Pub. Resources Code § 25500). Under the act, the Energy Commission's certificate is "in lieu of" other state, local, and regional permits (*ibid*.) The Commission's streamlined permitting process accomplishes a primary objective of the Renewable Energy Action Team, as identified in the Governor's Executive Order S-14-08 — to create a "one stop" process for permitting renewable energy generation facilities under California law. Accordingly, Commission staff has coordinated joint environmental review with the California Department of Fish and Game and the California State Water Resources Control Board, as well as the U.S. Fish and Wildlife Service. Staff has incorporated all required terms and conditions that might otherwise be included in state permits into the Energy Commission's certification process. The conditions of certification described below satisfy the following state LORS and take the place of terms and conditions that, but for the Commission's exclusive authority, would have been included in the following state permits:

> **Incidental Take Permit: California Endangered Species Act (Fish and Game Code §§ 2050 et seq.)** The California Endangered Species Act (CESA) prohibits the "take" (defined as "to hunt, pursue, catch, capture, or kill") of state-listed species except as otherwise provided in state law. Construction and operation of the BSEP project could result in the take of desert tortoise and Mohave ground squirrel, both listed as threatened under CESA. Staff has reviewed information supplied by the applicant (BS 2008i) and has coordinated closely with CDFG to develop the conditions of certification in this section. These conditions of certification would ensure that the project is not likely to jeopardize the continued existence of desert tortoise or Mohave ground squirrel or result in the degradation of occupied habitat. Energy Commission staff has also determined, in consultation with the CDFG, that: 1) the take is incidental to otherwise lawful activities, 2) impacts of the take are minimized and fully mitigated, and 3) the applicant has provided assurance of adequate funding to implement the conditions of certification.

Streambed Alteration Agreement: California Fish and Game Code §§ 1600 1607. Pursuant to these sections, CDFG typically regulates all changes to the natural flow, bed, or bank, of any river, stream, or lake that supports fish or wildlife resources. Construction of the BSEP would result in permanent impacts to 16 acres of state jurisdictional waters. Staff has reviewed information supplied by the applicant (DB 2008e) and has coordinated closely with CDFG to develop staff's proposed Conditions of Certification **BIO-18**. Implementation of this condition would minimize and offset impacts to state waters and would assure compliance with CDFG codes that provide protection to state waters.

Potential take of the desert tortoise, listed as threatened by the USFWS, requires compliance with the federal Endangered Species Act (ESA) (16 USC §§ 1531 et seq.) "Take" of a federally-listed species is prohibited without an Incidental Take Permit, which may be obtained through Section 7 consultation (between federal agencies) or a Section 10 Habitat Conservation Plan. The BSEP does not involve federal action; therefore the project will obtain take authorization through Section 10 of the Endangered Species Act (ESA). Section 10 permitting requires preparation of a Habitat Conservation Plan (HCP) to ensure the continued viability of listed species and their habitats, followed by issuance of an Incidental Take Permit and preparation of an Implementation Agreement. The Ventura Field Office of the USFWS oversees ESA permitting actions in the project area, and the applicant has determined that the project qualifies for a Low-Effect HCP process (BS 2008a). Staff's proposed Condition of Certification **BIO-9** also requires the applicant to implement all terms and conditions developed as part of the Low-Effect HCP process. Staff's proposed Conditions of Certification **BIO-9** through **BIO-13** were developed in consultation with USFWS and are likely to be consistent with terms and conditions required as part of the Low-Effect HCP. These conditions of certification would ensure that the project is not likely to adversely affect the desert tortoise or its critical habitat.

FACILITY CLOSURE

In the future, BSEP would experience either a planned closure or be unexpectedly (either temporarily or permanently) closed. When facility closure occurs, it must be done in such a way as to protect the environment and public health and safety. A closure plan would be prepared by the project owner prior to any planned closure (BS 2008a). To address unanticipated facility closure, an "on-site contingency plan" would be developed by the project owner and approved by the Energy Commission Compliance Project Manager (CPM). Facility closure requirements are discussed in more detail in the **General Conditions** section of this Preliminary Staff Assessment. Facility closure mitigation measures would also be included in the Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) prepared by the project owner and described in staff's proposed Condition of Certification **BIO-7.**

The facility closure plan should address habitat restoration measures to be implemented in the event of a planned or an unexpected permanent closure and must also include a funding mechanism to ensure sufficient funds are available for decommissioning and habitat restoration. Planned or unexpected permanent facility closure should address the removal of the transmission conductors since birds are known to collide with transmission line ground wires.

Staff's proposed Condition of Certification **BIO-19** contains measures to ensure that impacts to biological resources are addressed prior to the planned permanent or unexpected permanent closure of the project.

CONCLUSIONS

<u>Overview of Vegetation/Wildlife Impacts:</u> Much of the 2,012-acre Beacon Solar Energy Project plant site is barren or sparsely vegetated due to past agricultural disturbances, but it nevertheless supports a diversity of mammals, birds, and reptiles, including some special-status wildlife species. Grading on the plant site would not directly or indirectly impact sensitive plant communities, rare plants, or wetlands, but would directly impact some wildlife and would result in removal of vegetation that provides cover, foraging, and breeding habitat. Construction of linear facilities also has potential for impacts to wildlife; transmission line construction west of State Route 14 would permanently impact approximately 5 acres of Mojave creosote bush scrub, which provides habitat for desert tortoise (federal- and state-listed as threatened) and Mohave ground squirrel (state-listed as threatened). Construction of the 17.6-mile gas pipeline would occur within the disturbed road shoulder, but nevertheless has potential to impact special-status species such as burrowing owl, Mohave ground squirrel, and desert tortoise. Potential direct and indirect construction impacts to vegetation and wildlife could be reduced to less-than-significant levels with avoidance and minimization measures described in staff's proposed Conditions of Certification **BIO-1** through **BIO-8**. Staff's proposed Conditions of Certification **BIO-1** through **BIO-5** requires qualified biologists, with authority to implement mitigation measures necessary to prevent impacts to biological resources, be on site during all construction activities. Staff's proposed Condition of Certification **BIO-6** requires the development and implementation of a Worker Environmental Awareness Program to train all workers to avoid impacts to sensitive species and their habitats. Staff's proposed Condition of Certification **BIO-7** requires the project owner to prepare and implement a Biological Resources Mitigation Implementation and Monitoring Plan that incorporates the mitigation and compliance measures required by local, state, and federal LORS regarding biological resources. Staff's proposed Condition of Certification **BIO-8** describes Best Management Practices requirements and other impact avoidance and minimization measures.

<u>Take of Listed Species:</u> Potential take of desert tortoise and Mohave ground squirrel and loss of habitat for these species would be fully mitigated with staff's proposed Conditions of Certification **BIO-9** through **BIO-12**. Staff's proposed Condition of Certification **BIO-11** requires the applicant to acquire, protect, and enhance approximately 115 acres of habitat suitable for these listed species, and the other conditions require impact avoidance and minimization measures. These conditions also satisfy the California Department of Fish and Game's requirements under section 2081 of the California Fish and Game Code.

<u>Raven Predation on Desert Tortoise:</u> Construction and operation of the project could provide attractants in the form of new nesting and roosting sites, trash, and water, which

draw unnaturally high numbers of desert tortoise predators such as the common raven. Increases in raven predation could contribute to the cumulative significant impacts to the Mojave Desert population of desert tortoise. Staff's proposed Condition of Certification **BIO-13** specifies that the applicant finalize its draft Raven Management and Monitoring Plan in consultation with staff, CDFG, and USFWS. Staff anticipates that the applicant will be able to produce a final plan prior to publication of the Final Staff Assessment and that implementation of the condition would reduce this impact to less-than-significant levels and to the satisfaction of all agencies.

<u>Migratory Birds/Burrowing Mammals</u>: Vegetation at the plant site and along linear facilities provides foraging, cover, and/or breeding habitat for migratory birds, including a number of special-status bird species confirmed to be present at the site (western burrowing owl, loggerhead shrike, LeConte's thrasher, and California horned lark). Migratory birds and their eggs and young are protected by the federal Migratory Bird Treaty Act and Fish and Game Code section 3503. Implementation of staff's proposed Conditions of Certification **BIO-8** (Impact Avoidance and Best Management Practices) and **BIO-15** (Pre-Construction Nest Surveys) would avoid these potentially significant impacts to nesting birds. Potential impacts to burrowing owls, which were documented nesting on the plant site, would be further mitigated by implementation of staff's proposed Condition of Certification **BIO-17**. This condition involves passive relocation of burrowing owls in the path of construction to a relocation area immediately north of the BSEP site, as well as acquisition of 20 acres of off-site lands suitable for burrowing owl.

American badgers were not detected during the surveys, but potential habitat is present for this species at the project site. Construction activities could also crush or entomb American badger, which are protected under Title 14, California Code of Regulations (sections 670.2 and 670.5). Staff's proposed Condition of Certification **BIO-16**, which requires preconstruction surveys and avoidance measures to protect badgers and kit fox, would avoid this potential impact. This condition would also protect desert kit fox, which are known to occur on the site, and which are protected under the California Code of Regulations, chapter 5, section 460.

<u>Threat to Migratory Birds from Evaporation Ponds:</u> The BSEP includes three evaporation ponds that will be a minimum of 44 acres in size. Staff, CDFG, and USFWS are concerned that the proposed ponds could attract ravens, which would in turn prey on desert tortoise in adjacent habitat areas, and could also harm waterfowl, shorebirds, and other resident or migratory birds due to selenium poisoning or hyper-saline conditions. The applicant has addressed these concerns by proposing several project design features for the evaporation ponds that would discourage bird use and has made suggestions for bird deterrence and monitoring measures to minimize potential harm to birds. This issue is not yet resolved, and staff has requested that the applicant develop a comprehensive draft Evaporation Pond Design, Monitoring, and Management Plan, and to incorporate any revisions to pond size or design (see the **Soils & Water** section). Once the document is reviewed and approved by CDFG, USFWS and staff, the plan will be incorporated into staff's proposed Condition of Certification **BIO-14**. This condition would reduce potential impacts of the evaporation ponds to less-than-significant levels.

<u>Impacts to Pine Tree Creek</u>: One of the most significant biological impacts of the project is elimination of Pine Tree Creek and another dry desert wash on the plant site,

resulting in loss of approximately 60 acres of desert wash scrub and 16 acres of jurisdictional waters of the state. While the vegetation in the desert wash is highly degraded by past agricultural activities, these washes are characterized by natural processes of soil deposition, channel formation, and development of microtopography and soil crusts, all of which support recruitment of native desert wash vegetation and provide wildlife habitat. The applicant proposes to replace the desert washes with an engineered diversion channel to the south and east of the project site and to replicate the hydrological and biological functions and processes in this new drainage.

Staff concurs with the applicant's goal of replacing the biological functions and values of the impacted desert wash with the re-routed drainage, but this issue is not yet resolved. Staff's proposed Condition of Certification **BIO-18** specifies that the applicant re-evaluate the design of the diversion channel, as recommended in the **Soil and Water** section, and develop a channel stabilization plan that incorporates native vegetation where appropriate. Staff also recommends that this revegetation effort be monitored for the life of the project. With implementation of staff's proposed Condition of Certification **BIO-18**, staff anticipates that impacts to 16 acres of state waters and loss of the hydrological and biological functions of the project site desert washes would be mitigated to less-than-significant levels. This condition would also fulfill requirements of CDFG's Lake and Streambed Alteration Agreement program.

With implementation of staff's proposed conditions of certification, construction and operation of the BSEP would comply with all federal, state, and local laws, ordinances, regulations, and standards relating to biological resources. Staff recommends adoption of the following conditions of certification to mitigate potential impacts to sensitive biological resources to less-than-significant levels.

PROPOSED CONDITIONS OF CERTIFICATION

DESIGNATED BIOLOGIST SELECTION

BIO-1 The project owner shall assign at least one Designated Biologist to the project. The project owner shall submit the resume of the proposed Designated Biologist, with at least three references and contact information, to the Energy Commission Compliance Project Manager (CPM) for approval in consultation with the California Department of Fish and Game (CDFG) and U.S. Fish and Wildlife Service (USFWS).

The Designated Biologist must meet the following minimum qualifications:

1. bachelor's degree in biological sciences, zoology, botany, ecology, or a closely related field;

2. three years of experience in field biology or current certification of a nationally recognized biological society, such as The Ecological Society of America or The Wildlife Society;

3. at least one year of field experience with biological resources found in or near the project area;

4. meet the USFWS Authorized Biologist qualifications criteria (USFWS 2008) and demonstrate familiarity with protocols and guidelines for the desert tortoise; and

5. possess a recovery permit for desert tortoise and a California ESA Memorandum of Understanding pursuant to Section 2081(a) for desert tortoise and Mohave ground squirrel or have adequate experience and qualifications to obtain these authorizations.

In lieu of the above requirements, the resume shall demonstrate to the satisfaction of the CPM, in consultation with CDFG and USFWS, that the proposed Designated Biologist or alternate has the appropriate training and background to effectively implement the conditions of certification.

Verification: The project owner shall submit the specified information at least 90 days prior to the start of any project-related site disturbance activities. No site or related facility activities shall commence until an approved Designated Biologist is available to be on site.

If a Designated Biologist needs to be replaced, the specified information of the proposed replacement must be submitted to the CPM at least 10 working days prior to the termination or release of the preceding Designated Biologist. In an emergency, the project owner shall immediately notify the CPM to discuss the qualifications and approval of a short-term replacement while a permanent Designated Biologist is proposed to the CPM for consideration.

Designated Biologists shall complete a USFWS Qualifications Form (USFWS 2008) (www.fws.gov/ventura/speciesinfo/protocols_guidelines) and submit it to the USFWS and CPM within 60 days prior to ground breaking for review and final approval.

DESIGNATED BIOLOGIST DUTIES

BIO-2 The project owner shall ensure that the Designated Biologist performs the following during any site (or related facilities) mobilization, ground disturbance, grading, construction, operation, and closure activities. The Designated Biologist may be assisted by the approved Biological Monitor(s) but remains the contact for the project owner and CPM. The Designated Biologist duties shall include the following:

1. Advise the project owner's Construction and Operation Managers on the implementation of the biological resources conditions of certification;

2. Consult on the preparation of the Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) to be submitted by the project owner;

3. Be available to supervise, conduct, and coordinate mitigation, monitoring, and other biological resources compliance efforts, particularly in areas requiring avoidance or containing sensitive biological resources, such as special-status species or their habitat;

4. Clearly mark sensitive biological resource areas and inspect these areas at appropriate intervals for compliance with regulatory terms and conditions;

5. Inspect active construction areas where animals may have become trapped prior to construction commencing each day. At the end of the day, inspect for the installation of structures that prevent entrapment or allow escape during periods of construction inactivity. Periodically inspect areas with high vehicle activity (e.g., parking lots) for animals in harm's way;

6. Notify the project owner and the CPM of any non-compliance with any biological resources condition of certification;

7. Respond directly to inquiries of the CPM regarding biological resource issues;

8. Maintain written records of the tasks specified above and those included in the BRMIMP. Summaries of these records shall be submitted in the Monthly Compliance Report and the Annual Compliance Report;

9. Train the Biological Monitors as appropriate, and ensure their familiarity with the BRMIMP, Worker Environmental Awareness Program (WEAP) training, and USFWS guidelines on desert tortoise surveys and handling procedures <www.fws.gov/ventura/speciesinfo/protocols_guidelines>, and

10. Maintain the ability to be in regular, direct communication with representatives of CDFG and USFWS, including notifying these agencies of dead or injured listed species and reporting special-status species observations to the California Natural Diversity Data Base.

Verification: The Designated Biologist shall submit in the Monthly Compliance Report to the CPM copies of all written reports and summaries that document biological resources activities. If actions may affect biological resources during operation a Designated Biologist shall be available for monitoring and reporting. During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report unless his/her duties cease, as approved by the CPM.

BIOLOGICAL MONITOR QUALIFICATIONS

BIO-3 The project owner's CPM-approved Designated Biologist shall submit the resume, at least three references, and contact information of the proposed Biological Monitors to the CPM for approval in consultation with CDFG and USFWS. The resume shall demonstrate, to the satisfaction of the CPM, the appropriate education and experience to accomplish the assigned biological resource tasks. Biological Monitors involved in any aspect of desert tortoise surveys or handling must meet the criteria to be considered a USFWS Authorized Biologist (USFWS 2008) and demonstrate familiarity with the most recent protocols and guidelines for the desert tortoise.

Biological Monitor(s) training by the Designated Biologist shall include familiarity with the conditions of certification, BRMIMP, WEAP, USFWS guidelines on desert tortoise surveys and handling procedures <www.fws.gov/ventura/speciesinfo/protocols_guidelines> and all permits.

Verification: The project owner shall submit the specified information to the CPM for approval at least 30 days prior to the start of any project-related site disturbance activities. The Designated Biologist shall submit a written statement to the CPM confirming that individual Biological Monitor(s) has been trained including the date when training was completed. If additional biological monitors are needed during construction the specified information shall be submitted to the CPM for approval at least 10 days prior to their first day of monitoring activities.

BIOLOGICAL MONITOR DUTIES

BIO-4 The Biological Monitors shall assist the Designated Biologist in conducting surveys and in monitoring of mobilization, ground disturbance, grading, construction, operation, and closure activities. The Designated Biologist shall remain the contact for the project owner and CPM.

Verification: The Designated Biologist shall submit in the Monthly Compliance Report to the CPM copies of all written reports and summaries that document biological resources activities, including those conducted or monitored by Biological Monitors. If actions may affect biological resources during operation a Biological Monitor, under the supervision of the Designated Biologist, shall be available for monitoring and reporting. During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report unless his/her duties cease, as approved by the CPM.

DESIGNATED BIOLOGIST AND BIOLOGICAL MONITOR AUTHORITY

BIO-5 The project owner's construction/operation manager shall act on the advice of the Designated Biologist and Biological Monitor(s) to ensure conformance with the biological resources conditions of certification.

The Designated Biologist shall have the authority to immediately stop any activity that is not in compliance with these conditions and/or order any reasonable measure to avoid take of an individual of a listed species. If required by the Designated Biologist and Biological Monitor(s) the project owner's construction/operation manager shall halt all site mobilization, ground disturbance, grading, construction, and operation activities in areas specified by the Designated Biologist. The Designated Biologist shall:

1. Require a halt to all activities in any area when determined that there would be an unauthorized adverse impact to biological resources if the activities continued;

2. Inform the project owner and the construction/operation manager when to resume activities; and

3. Notify the CPM if there is a halt of any activities and advise the CPM of any corrective actions that have been taken or will be instituted as a result of the work stoppage.

4. If the Designated Biologist is unavailable for direct consultation, the Biological Monitor shall act on behalf of the Designated Biologist.

Verification: The project owner shall ensure that the Designated Biologist or Biological Monitor notifies the CPM immediately (and no later than the morning following the incident, or Monday morning in the case of a weekend) of any non-compliance or a halt of any site mobilization, ground disturbance, grading, construction, and operation activities. The project owner shall notify the CPM of the circumstances and actions being taken to resolve the problem.

Whenever corrective action is taken by the project owner, a determination of success or failure will be made by the CPM within five working days after receipt of notice that corrective action is completed, or the project owner will be notified by the CPM that coordination with other agencies will require additional time before a determination can be made.

WORKER ENVIRONMENTAL AWARENESS PROGRAM (WEAP)

BIO-6 The project owner shall develop and implement BSEP-specific Worker Environmental Awareness Program (WEAP) and shall secure approval for the WEAP from USFWS, CDFG, and the CPM. The WEAP shall be administered to all on-site personnel including surveyors, construction engineers, employees, contractors, contractor's employees, supervisors, inspectors, subcontractors, and delivery personnel. The WEAP shall be implemented during site mobilization, ground disturbance, grading, construction, operation, and closure. The WEAP shall:

1. be developed by or in consultation with the Designated Biologist and consist of an on-site or training center presentation in which supporting written material and electronic media is made available to all participants;

2. discuss the locations and types of sensitive biological resources on the project site and adjacent areas and explain the reasons for protecting these resources;

3. place special emphasis on desert tortoise, including information on physical characteristics, distribution, behavior, ecology, sensitivity to human activities, legal protection, penalties for violations, reporting requirements, and protection measures;

4. include a discussion of fire prevention measures to be implemented by workers during project activities;

5. present the meaning of various temporary and permanent habitat protection measures;

6. identify whom to contact if there are further comments and questions about the material discussed in the program; and

7. include a training acknowledgment form to be signed by each worker indicating that he/she received training and shall abide by the guidelines.

The specific program can be administered by a competent individual(s) acceptable to the Designated Biologist.

<u>Verification:</u> At least 60 days prior to the start of any project-related site disturbance activities, the project owner shall provide to the CPM a copy of the draft WEAP and all supporting written materials and electronic media prepared or reviewed by the Designated Biologist and a resume of the person(s) administering the program.

The project owner shall provide in the Monthly Compliance Report the number of persons who have completed the training in the prior month and a running total of all persons who have completed the training to date. At least 10 days prior to site and related facilities mobilization, the project owner shall submit two copies of the CPM-approved final WEAP.

Training acknowledgement forms signed during construction shall be kept on file by the project owner for at least six months after the start of commercial operation.

Throughout the life of the Project, the worker education program shall be repeated annually for permanent employees, and shall be routinely administered within one week of arrival to any new construction personnel, foremen, contractors, subcontractors, and other personnel potentially working within the Project area. Upon completion of the orientation, employees shall sign a form stating that they attended the program and understand all protection measures. These forms shall be maintained by the project owner and shall be made available to the CPM upon request. Workers shall receive and be required to visibly display a hardhat sticker or certificate that they have completed the training.

During project operation, signed statements for operational personnel shall be kept on file for six months following the termination of an individual's employment.

BIOLOGICAL RESOURCES MITIGATION IMPLEMENTATION AND MONITORING PLAN

BIO-7 The project owner shall develop a Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) and submit two copies of the proposed BRMIMP to the CPM (for review and approval) and shall implement the measures identified in the approved BRMIMP. The BRMIMP shall incorporate impact avoidance and minimization measures described in final versions of the Raven Management Plan, the Burrowing Owl Mitigation and Monitoring Plan, and the Closure Plan.

The BRMIMP shall be prepared in consultation with the Designated Biologist and shall include the following:

1. all biological resources mitigation, monitoring, and compliance measures proposed and agreed to by the project owner;

2. all biological resources conditions of certification identified as necessary to avoid or mitigate impacts;

3. all biological resource mitigation, monitoring, and compliance measures required in federal agency terms and conditions, such as those provided in the USFWS Habitat Conservation Plan/Implementing Agreement (HCP/IA);

4. all sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation, and closure;

5. all required mitigation measures for each sensitive biological resource;

6. a detailed description of measures that shall be taken to avoid or mitigate temporary disturbances from construction activities;

7. all locations on a map, at an approved scale, of sensitive biological resource areas subject to disturbance and areas requiring temporary protection and avoidance during construction;

8. aerial photographs, at an approved scale, of all areas to be disturbed during project construction activities; include one set <u>prior</u> to any site or related facilities mobilization disturbance and one set <u>subsequent</u> to completion of project construction. Provide planned timing of aerial photography and a description of why times were chosen. Provide a final accounting of the before/after acreages and a determination of whether additional habitat compensation is necessary in the Construction Termination Report;

9. duration for each type of monitoring and a description of monitoring methodologies and frequency;

10. performance standards to be used to help decide if/when proposed mitigation is or is not successful;

11. all performance standards and remedial measures to be implemented if performance standards are not met;

12. a discussion of biological resources-related facility closure measures including a description of funding mechanism(s);

13. a process for proposing plan modifications to the CPM and appropriate agencies for review and approval; and

14. copies of all biological resources-related permits obtained.

<u>Verification:</u> The project owner shall submit the BRMIMP to the CPM at least 60 days prior to start of any project-related site disturbance activities. The CPM, in consultation with other appropriate agencies, will determine the BRMIMP's acceptability within 45 days of receipt. The BRMIMP shall contain all of the required measures included in all biological conditions of certification. No ground disturbance may occur prior to the CPM's approval of the final BRMIMP.

The project owner shall notify the CPM no less than five working days before implementing any modifications to the approved BRMIMP to obtain CPM approval. Any changes to the approved BRMIMP must also be approved by the CPM in consultation with appropriate agencies to ensure no conflicts exist.

Implementation of BRMIMP measures (construction activities that were monitored, species observed) will be reported in the Monthly Compliance Reports by the Designated Biologist. Within 30 days after completion of project construction, the project owner shall provide to the CPM, for review and approval, a written construction termination report identifying which items of the BRMIMP have been completed; a summary of all modifications to mitigation measures made during the project's site mobilization, ground disturbance, grading, and construction phases; and which mitigation and monitoring items are still outstanding.

IMPACT AVOIDANCE AND MINIMIZATION MEASURES

BIO-8 The project owner shall undertake the following measures to manage the construction site and related facilities in a manner to avoid or minimize impacts to biological resources:

1. Limit Disturbance Area. The boundaries of all areas to be disturbed (including staging areas, access roads, and sites for temporary placement of spoils) shall be delineated with stakes and flagging prior to construction activities in consultation with the Designated Biologist. Spoils shall be stockpiled in disturbed areas lacking native vegetation and which do not provide habitat for special-status species. Parking areas, staging and disposal site locations shall similarly be located in areas without native vegetation or special-status species habitat. All disturbances, vehicles, and equipment shall be confined to the flagged areas.

2. Minimize Road Impacts. New and existing roads that are planned for construction, widening, or other improvements shall not extend beyond the flagged impact area as described above. All vehicles passing or turning around will do so within the planned impact area or in previously disturbed areas. Where new access is required outside of existing roads (e.g. new spur roads associated with both transmission line options) or the construction zone, the route will be clearly marked (i.e., flagged and/or staked) prior to the onset of construction.

3. Minimize Traffic Impacts. Vehicular traffic during project construction and operation shall be confined to existing routes of travel to and from the project site, and cross country vehicle and equipment use outside designated work areas shall be prohibited. The speed limit shall not exceed 25 miles per hour within the project area, on maintenance roads for linear facilities, or on access roads to the BSEP site.

4. Monitor During Construction. The Designated Biologist or Biological Monitor shall be present at the construction site during all project

activities that have potential to disturb soil, vegetation, and wildlife. The biologist shall walk immediately ahead of equipment during brushing and grading activities.

5. Minimize Impacts of Transmission Lines, Roads, Staging Areas. Transmission lines, access roads, pulling sites, and storage and parking areas shall be designed, installed, and maintained with the goal of minimizing impacts to native plant communities and sensitive biological resources. Transmission lines and all electrical components shall be designed, installed, and maintained in accordance with the Avian Power Line Interaction Committee's (APLIC's) *Suggested Practices for Avian Protection on Power Lines* (APLIC 2006) and *Mitigating Bird Collisions with Power Lines* (APLIC 2004) to reduce the likelihood of large bird electrocutions and collisions.

6. Avoid Use of Toxic Substances. Road surfacing and sealants as well as soil bonding and weighting agents used on unpaved surfaces shall be non-toxic to wildlife and plants.

7. Minimize Lighting Impacts. Facility lighting shall be designed, installed, and maintained to prevent side casting of light towards wildlife habitat.

8. Avoid Vehicle Impacts to Desert Tortoise. Parking and storage shall occur within the desert tortoise exclusion fencing to the extent feasible. If a vehicle or construction equipment parks for longer than two minutes outside the fenced area, the ground beneath the vehicle shall be inspected for the presence of desert tortoise before it is moved. If a desert tortoise is observed, it will be left to move on its own. If it does not move within 15 minutes, a Biological Monitor may remove and relocate the animal to a safe location if temperatures are within the range described in the USFWS protocol (Desert Tortoise Council 1994).

9. Avoid Wildlife Pitfalls. At the end of each work day, the Designated Biologist shall ensure that all potential wildlife pitfalls (trenches, bores, and other excavations) outside the permanently fenced area have been backfilled. If backfilling is not feasible, all trenches, bores, and other excavations shall be sloped at a 3:1 ratio at the ends to provide wildlife escape ramps, or covered completely to prevent wildlife access, or fully enclosed with tortoise-proof fencing. All trenches, bores, and other excavations outside the permanently fenced area shall be inspected periodically throughout and at the end of each workday by the Designated Biologist or a Biological Monitor. Should a tortoise or other wildlife become trapped, the Designated Biologist or Biological Monitor shall remove and relocate the individual to a safe location. Any wildlife encountered during the course of construction shall be allowed to leave the construction area unharmed.

10. Avoid Entrapment of Desert Tortoise. Any construction pipe, culvert, or similar structure with a diameter greater than 3 inches, stored less than 8

inches above ground and within desert tortoise habitat (i.e., outside the permanently fenced area) for one or more nights, shall be inspected for tortoises before the material is moved, buried, or capped. As an alternative, all such structures may be capped before being stored outside the fenced area, or placed on pipe racks. These materials would not need to be inspected or capped if they are stored within the permanently fenced area after the clearance surveys have been completed.

11. Minimize Standing Water. Water applied to dirt roads and construction areas (trenches or spoil piles) for dust abatement shall use the minimal amount needed to meet safety and air quality standards in an effort to prevent the formation of puddles, which could attract desert tortoises and common ravens to construction sites. A Biological Monitor shall patrol these areas to ensure water does not puddle and attract desert tortoise, common ravens, and other wildlife to the site and shall take appropriate action to reduce water application where necessary.

12. Minimize Spills of Hazardous Materials. All vehicles and equipment shall be maintained in proper working condition to minimize the potential for fugitive emissions of motor oil, antifreeze, hydraulic fluid, grease, or other hazardous materials. The Designated Biologist shall be informed of any hazardous spills immediately as directed in the project Hazardous Materials Plan. Hazardous spills shall be immediately cleaned up and the contaminated soil properly disposed of at a licensed facility. Servicing of construction equipment shall take place only at a designated area. Service/maintenance vehicles shall carry a bucket and pads to absorb leaks or spills.

13. Worker Guidelines. During construction all trash and food-related waste shall be placed in self-closing containers and removed daily from the site. Workers shall not feed wildlife or bring pets to the project site. Except for law enforcement personnel, no workers or visitors to the site shall bring firearms or weapons.

14. Avoid Spread of Noxious Weeds. The project owner shall implement the following Best Management Practices during construction and operation to prevent the spread and propagation of noxious weeds:

    a. Limit the size of any vegetation and/or ground disturbance to the absolute minimum and limit ingress and egress to defined routes;

    b. Prevent spread of non-native plants via vehicular sources by implementing Trackclean™ or other methods of vehicle cleaning for vehicles coming and going from construction sites. Earth-moving equipment shall be cleaned prior to transport to the construction site;

    c. Use only weed-free straw, hay bales, and seed for erosion control and sediment barrier installationsl, and

d. Avoid using invasive non-native species in landscaping plans and erosion control.

15. Implement Erosion Control Measures. Standard erosion control measures shall be implemented for all phases of construction and operation where sediment run-off from exposed slopes threatens to enter "Waters of the State". Sediment and other flow-restricting materials shall be moved to a location where they shall not be washed back into the stream. All disturbed soils and roads within the project site shall be stabilized to reduce erosion potential, both during and following construction. Areas of disturbed soils (access and staging areas) with slopes toward a drainage shall be stabilized to reduce erosion potential.

16. Monitor Ground Disturbing Activities Prior to Site Mobilization. If ground-disturbing activities are required prior to site mobilization, such as for geotechnical borings or hazardous waste evaluations, a Designated Biologist shall be present to monitor any actions that could disturb soil, vegetation, or wildlife.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP and implemented. Implementation of the measures will be reported in the Monthly Compliance Reports by the Designated Biologist. Within 30 days after completion of project construction, the project owner shall provide to the CPM, for review and approval, a written construction termination report identifying how measures have been completed.

DESERT TORTOISE CLEARANCE SURVEYS AND FENCING

BIO-9 The project owner shall undertake appropriate measures to manage construction at the plant site and linear facilities in a manner to avoid or minimize impacts to desert tortoise. Methods for clearance surveys, fence installation, tortoise handling, artificial burrow construction, egg handling and other procedures shall be consistent with those described in the *Guidelines for Handling Desert Tortoise during Construction Projects* (Desert Tortoise Council 1999) or more current guidance provided by USFWS. The project owner shall also implement terms and conditions developed as part of the Section 10 Low-Effect Habitat Conservation Plan process with USFWS. These measures include, but are not limited to, the following:

1. Fence Installation. Prior to ground disturbance, the entire plant site (east of the railroad tracks) shall be fenced with permanent desert tortoise-proof fence. To avoid impacts to desert tortoise during fence construction, the proposed fence alignment shall be flagged and the alignment surveyed within 24 hours prior to fence construction. Surveys shall be conducted by Designated Biologist using techniques approved by the USFWS and CDFG. Biological Monitors may assist the Designated Biologist under his or her supervision. These surveys shall provide 100 percent coverage of all areas to be disturbed during fence construction and an additional transect along both sides of the proposed fence line. This fence line transect shall cover an area approximately 90 feet wide centered on the fence alignment. Transects shall be no greater than 30 feet apart. All

desert tortoise burrows, and burrows constructed by other species that might be used by desert tortoises, shall be examined to assess occupancy of each burrow by desert tortoises and handled in accordance with USFWS-approved protocol.

a. Timing, Supervision of Fence Installation. The exclusion fencing shall be installed prior to the onset of clearing and grubbing. The fence installation shall be supervised by the Designated Biologist and monitored by the Biological Monitors.

b. Fence Material and Installation. The permanent tortoise exclusionary fencing shall consist of galvanized hard wire cloth 1-cm mesh sunk 15 cm into the ground, and between 46 to 61 cm above ground (USFWS 2008a, Appendix D).

c. Security Gates. Security gates shall be designed with minimal ground clearance to deter ingress by tortoises. The gates may be electronically activated to open and close immediately after vehicle(s) have entered or exited to prevent extended periods with open gates, which might lead to a tortoise entering. Cattle grating shall be installed at the gated entries to discourage tortoises from gaining entry.

d. Utility Corridor Fencing. Utility corridors and tower locations shall be temporarily fenced with tortoise exclusion fencing to prevent desert tortoise entry during construction. Temporary fencing must follow guidelines for permanent fencing and supporting stakes shall be sufficiently spaced to maintain fence integrity.

e. Fence Inspections. Following installation of both the permanent site fencing and temporary fencing in the utility corridor, the fencing shall be inspected monthly and during/following all major rainfall events. Any damage to the fencing shall be repaired within two days of observing damage. Inspections of permanent site fencing shall occur for the life of the project.

2. Desert Tortoise Clearance Surveys. Following construction of the tortoise exclusion fences, all fenced areas shall be cleared of tortoises by the Designated Biologist, who may be assisted by Biological Monitors. A minimum of two clearance surveys, with negative results, must be completed, and these must coincide with heightened desert tortoise activity from late March through May and during October. The second clearance survey shall be walked at 90 degrees to the orientation of the first clearance survey.

3. Relocation for Desert Tortoise West of SR 14. If desert tortoises are detected during clearance surveys within the project impact area west of SR 14, the Designated Biologist shall move the tortoise the shortest possible distance, keeping it out of harm’s way but still within its home range. Any relocation efforts shall be in accordance with techniques

described in the *Guidelines for Handling Desert Tortoise during Construction Projects* (Desert Tortoise Council 1999) or more current guidance on the USFWS website.

4. Translocation Plan for Desert Tortoise East of SR-14. To address desert tortoise encountered during clearance surveys within the project impact area east of SR 14, the project owner shall develop and implement a desert tortoise Translocation Plan. The Translocation Plan shall be consistent with current USFWS approved guidelines, and shall be approved by Energy Commission staff in consultation with USFWS and CDFG. The Translocation Plan shall designate a translocation site as close as possible to the project, and which provides suitable conditions for long-term survival of the relocated desert tortoise.

5. Burrow Inspection. All potential desert tortoise burrows within the fenced area shall be searched for presence. In some cases, a fiber optic scope may be needed to determine presence or absence within a deep burrow. To prevent reentry by a tortoise or other wildlife, all burrows shall be collapsed once absence has been determined. Tortoises excavated from burrows shall be relocated to unoccupied natural or artificial burrows immediately following excavation in an area approved by the Designated Biologist.

6. Burrow Excavation. Burrows inhabited by tortoises shall be excavated by the Designated Biologist using hand tools, and then collapsed or blocked to prevent re-occupation. If excavated during May through July, the Designated Biologist shall search for desert tortoise nests/eggs, which are typically located near the entrance to burrows. All desert tortoise handling and removal, and burrow excavations, including nests, shall be conducted by the Designated Biologist in accordance with the service-approved protocol (Desert Tortoise Council 1999).

7. Monitoring During Clearing. Following the tortoise clearance and translocation, heavy equipment shall be allowed to enter the project site to perform earth work such as clearing, grubbing, leveling, and trenching. A Biological Monitor shall monitor initial clearing and grading activities to find and move tortoises missed during the initial tortoise clearance survey process. Should a tortoise be discovered, it shall be relocated as described above. Any pre-activity tortoise surveys for other construction areas shall be performed within 72 hours of ground disturbing activities.

8. Reporting. The Designated Biologist shall record the following information for any desert tortoises handled: a) the locations (narrative and maps) and dates of observation; b) general condition and health, including injuries, state of healing and whether desert tortoise voided their bladders; c) location moved from and location moved to (using GPS technology); d) diagnostic markings (i.e., identification numbers or marked lateral scutes); e) ambient temperature when handled and released; and f) digital photograph of each handled desert tortoise as described in the paragraph

below. Desert tortoise moved from within project areas shall be marked for future identification as described in *Guidelines for Handling Desert Tortoise during Construction Projects* (Desert Tortoise Council 1999) or more current guidance on the USFWS website. Digital photographs of the carapace, plastron, and fourth costal scute shall be taken. Scutes shall not be notched for identification.

Verification: Within 30 days of completion of desert tortoise clearance surveys the Designated Biologist shall submit a report to the CPM, USFWS, and CDFG describing how mitigation measures described above have been satisfied. The report shall include the desert tortoise survey results, capture and release locations of any relocated desert tortoises, and any other information needed to demonstrate compliance with the measures described above.

Prior to publication of the Final Staff Assessment the project owner shall submit to Energy Commission Staff, USFWS and CDFG a draft Translocation Plan. At least 60 days prior to start of any project-related ground disturbance activities, the project owner shall provide the CPM with the final version of a Translocation Plan that has been approved by Energy Commission staff in consultation with USFWS and CDFG. The CPM will determine the plan’s acceptability within 15 days of receipt of the final plan. All modifications to the approved translocation must be made only after approval the Energy Commission staff in consultation with USFWS and CDFG. The project owner shall notify the CPM no fewer than 5 working days before implementing any CPM-approved modifications to the Translocation Plan.

Within 30 days after initiation of translocation activities, the Designated Biologist shall provide to the CPM for review and approval, a written report identifying which items of the Translocation Plan have been completed, and a summary of all modifications to measures made during implementation.

MOHAVE GROUND SQUIRREL CLEARANCE SURVEYS

BIO-10 The project owner shall undertake appropriate measures to manage construction at the plant site and linear facilities in a manner to avoid or minimize impacts to Mohave ground squirrel. These measures include, but are not limited to, the following:

1. Clearance Survey. After the installation of the exclusion fence and prior to any ground disturbance, the Designated Biologist(s) shall examine the area to be disturbed for Mohave ground squirrels and their burrows. The survey shall provide 100 percent coverage of the Project limits. The use of specialized equipment (e.g. fiber optics) may be necessary to thoroughly inspect all potential Mohave ground squirrel burrows. Potentially occupied burrows shall be fully excavated by hand by the Designated Biologist(s).

2. Translocation Plan. The project owner shall develop and implement a Mohave ground squirrel translocation plan to address the handling and disposition of any Mohave ground squirrels encountered during the clearance surveys. The Translocation Plan shall be approved by Energy Commission staff in consultation with CDFG. The Translocation Plan shall

designate a translocation site as close as possible to the project, and which provides suitable conditions for long-term survival of the relocated Mohave ground squirrel.

3. Records of Capture. If Mohave ground squirrels are captured via trapping or burrow excavation, the Designated Biologist shall maintain a record of each Mohave ground squirrels handled, including: a) the locations (Global Positioning System [GPS] coordinates and maps) and time of capture and/or observation as well as release; b) sex; c) approximate age (adult/juvenile); d) weight; e) general condition and health, noting all visible conditions including gait and behavior, diarrhea, emaciation, salivation, hair loss, ectoparasites, and injuries; and f) ambient temperature when handled and released.

Verification: Within 30 days of completion of Mohave ground squirrel clearance surveys the Designated Biologist shall submit a report to the CPM and CDFG describing how mitigation measures described above have been satisfied. The report shall include the Mohave ground squirrel survey results, capture and release locations of any relocated squirrels, and any other information needed to demonstrate compliance with the measures described above.

Prior to publication of the Final Staff Assessment the project owner shall submit to Energy Commission Staff, USFWS and CDFG a draft Mohave Ground Squirrel Translocation Plan. At least 60 days prior to start of any project-related ground disturbance activities, the project owner shall provide the CPM with the final version of a Mohave Ground Squirrel Translocation Plan that has been approved by Energy Commission staff in consultation with USFWS and CDFG. The CPM will determine the plan's acceptability within 15 days of receipt of the final plan. All modifications to the approved translocation must be made only after approval the Energy Commission staff in consultation with CDFG. The project owner shall notify the CPM no fewer than 5 working days before implementing any CPM-approved modifications to the Translocation Plan.

Within 30 days after initiation of translocation activities, the Designated Biologist shall provide to the CPM for review and approval, a written report identifying which items of the Translocation Plan have been completed, and a summary of all modifications to measures made during implementation.

DESERT TORTOISE AND MOHAVE GROUND SQUIRREL COMPENSATORY MITIGATION

BIO-11 To fully mitigate for habitat loss and potential take of desert tortoise and Mohave ground squirrel, the project owner shall acquire, in fee or in easement, no less than 115 acres (for transmission line Option 1) or no less than 117.4 acres (for transmission line Option 2) of land suitable for these species and shall provide funding for the enhancement and long-term management of these compensation lands. The responsibilities for acquisition and management of the compensation lands may be delegated by written agreement to CDFG or to a third party, such as a non-governmental organization dedicated to Mojave Desert habitat conservation, subject to approval by the CPM, in consultation with CDFG and USFWS prior to land acquisition or management activities. If habitat disturbance exceeds that described in this analysis, the project owner shall be responsible for acquisition and management of additional compensation lands or additional funds required to compensate for any additional habitat disturbances. Additional funds shall be based on the adjusted market value of compensation lands at the time of construction to acquire and manage habitat. The acquisition and management of compensation lands shall include the following elements:

1. <u>Selection Criteria for Compensation Lands.</u> The compensation lands selected for acquisition shall:

    a. be in the western Mojave Desert;

    b. provide moderate to good quality habitat for Mohave ground squirrel and desert tortoise with capacity to improve in quality and value for these species;

    c. be a contiguous block of land (preferably) or located so they result in a contiguous block of protected habitat;

    d. be adjacent to larger blocks of lands that are already protected;

    e. be connected to lands currently occupied by desert tortoise and Mohave ground squirrel, ideally with populations that are stable, recovering, or likely to recover;

    f. not have a history of intensive recreational use, grazing, or other disturbance that might make habitat recovery and restoration infeasible;

    g. not be characterized by high densities of invasive species, either on or immediately adjacent to the parcels under consideration, that might jeopardize habitat recovery and restoration; and

    h. not encumbered by easements or uses that would preclude fencing of the site or preclude management of the site for the primary benefit of the species for which mitigation lands were secured.

2. <u>Review and Approval of Compensation Lands Prior to Acquisition.</u> A minimum of two months prior to acquisition of the property, the project owner, or a third-party approved by the CPM, in consultation with CDFG and USFWS, shall submit a formal acquisition proposal to the CPM, CDFG, and USFWS describing the parcel(s) intended for purchase. This acquisition proposal shall discuss the suitability of the proposed parcel(s) as compensation lands for desert tortoise and Mohave ground squirrel in relation to the criteria listed above. Approval from the CPM, in consultation

with USFWS and CDFG, shall be required for acquisition of all parcels comprising the 115.0 acres (117.4 acres if Option 2 is adopted) in advance of purchase.

3. Mitigation Security for Compensation Lands and Avoidance/Minimization Measures. The project owner or an approved third party shall complete acquisition of the proposed compensation lands prior to initiating ground-disturbing project activities. The project owner shall also provide financial assurances to the CPM, with copies of the document(s) to CDFG and USFWS, to guarantee that an adequate level of funding is available to implement all impact avoidance, minimization, and compensation measures described in Conditions of Certification **BIO-9** through **BIO-12**. Financial assurance shall be provided to the CPM in the form of an irrevocable letter of credit or another form of security ("Security") approved by the CPM, prior to initiating ground-disturbing project activities. If necessary to draw on these funds, such funds shall be used solely for implementation of the measures associated with the project.

   Prior to submittal to the CPM, the Security shall be approved by the CPM, in consultation with CDFG, to ensure funding in the amount of $529,000.00 (if transmission line Option 1 is adopted) or $540,040.00 (if transmission line Option 2 is adopted). These Security amounts were calculated as follows and may be revised upon completion of a Property Analysis Record (PAR) or PAR-like analysis of the proposed compensation lands:

   a. land acquisition costs for compensation lands, calculated at $3,000/acre for 115 acres (117.4 acres if Option 2 is adopted): $345,000.00; or $352,200.00 (if Option 2 is adopted);

   b. costs of enhancing compensation lands, calculated at $250/acre for 115 acres (117.4 acres if Option 2 is adopted): $28,750; or $29,350 (if Option 2 is adopted); and

   c. costs of establishing an endowment for long-term management of compensation lands, calculated at $1,350/acre for 115 acres (117.4 acres if Option 2 is adopted): $155,250 or $158,490 (if Option 2 is adopted).

   If Security is provided, the project owner, or an approved third party, shall complete the proposed compensation lands acquisition within 12 months of the start of project ground-disturbing activities.

4. Compensation Lands Acquisition Conditions. The project owner shall comply with the following conditions relating to acquisition of compensation lands after the CPM, in consultation with CDFG and USFWS, has approved the proposed compensation lands and received Security, if any, as described above.

   a. Preliminary Report: The project owner, or approved third party, shall provide a recent preliminary title report, initial hazardous materials survey report, biological analysis, and other necessary documents for the proposed 115 acres (117.4 acres if Option 2 is adopted [and/or a conservation easement]). All documents conveying or conserving compensation lands and all conditions of title/easement are subject to a field review and approval by the CPM, in consultation with CDFG and USFWS, California Department of General Services and, if applicable, the Fish and Game Commission and/or the Wildlife Conservation Board.

b. Title/Conveyance: The project owner shall transfer fee title or a conservation easement to the 115 acres (117.4 acres if Option 2 is adopted) of compensation lands to CDFG under terms approved by CDFG. Alternatively, a non-profit organization qualified to manage compensation lands (pursuant to California Government Code section 65965) and approved by CDFG and the CPM may hold fee title or a conservation easement over the habitat mitigation lands. If the approved non-profit organization holds title, a conservation easement shall be recorded in favor of CDFG in a form approved by CDFG. If the approved non-profit holds a conservation easement, CDFG shall be named a third party beneficiary. If a Security is provided, the project owner or an approved third party shall complete the proposed compensation lands acquisition within 12 months of the start of project ground-disturbing activities.

c. Enhancement Fund. The project owner shall fund the initial protection and enhancement of the 115 acres (117.4 acres if Option 2 is adopted) by providing the enhancement funds to the CDFG. Alternatively, a non-profit organization may hold the enhancement funds if they are qualified to manage the compensation lands (pursuant to California Government Code section 65965) and if they meet the approval of CDFG and the CPM. If CDFG takes fee title to the compensation lands, the enhancement fund must go to CDFG.

d. Endowment Fund. Prior to ground-disturbing project activities, the project owner shall provide to CDFG a capital endowment in the amount determined through the Property Analysis Record (PAR) or PAR-like analysis that will be conducted for the 115 acres (117.4 acres if Option 2 is adopted) of compensation lands. Alternatively, a non-profit organization may hold the endowment fees if they are qualified to manage the compensation lands (pursuant to California Government Code section 65965) and if they meet the approval of CDFG and the CPM. If CDFG takes fee title to the compensation lands, the endowment must go to CDFG, where it will be held in the special deposit fund established pursuant to California Government Code section 16370. If the special deposit fund is not used to manage the endowment, the California Wildlife Foundation shall manage the endowment for CDFG and with CDFG guidance.

e. The project owner and the CPM shall ensure that an agreement is in place with the endowment holder/manager to ensure the following conditions:

- Interest. Interest generated from the initial capital endowment shall be available for reinvestment into the principal and for the long-term operation, management, and protection of the approved compensation lands, including reasonable administrative overhead, biological monitoring, improvements to carrying capacity, law enforcement measures, and any other action designed to protect or improve the habitat values of the compensation lands.

- Withdrawal of Principal. The endowment principal shall not be drawn upon unless such withdrawal is deemed necessary by the CDFG or the approved third-party endowment manager to ensure the continued viability of the species on the 115 acres (117.4 acres if Option 2 is adopted). If CDFG takes fee title to the compensation lands, monies received by CDFG pursuant to this provision shall be deposited in a special deposit fund established pursuant to Government Code section 16370. If the special deposit fund is not used to manage the endowment, the California Wildlife Foundation will manage the endowment for CDFG with CDFG guidance.

- Pooling Endowment Funds. CDFG, or a CPM- and CDFG-approved non-profit organization qualified to hold endowments pursuant to California Government Code section 65965, may pool the endowment with other endowments for the operation, management, and protection of the 115 acres (117.4 acres if Option 2 is adopted) for local populations of desert tortoise and Mohave ground squirrel. However, for reporting purposes, the endowment fund must be tracked and reported individually.

f. Reimbursement Fund: The project owner shall provide reimbursement to the CDFG or approved third party for reasonable expenses incurred during title, easement, and documentation review; expenses incurred from other state agency reviews; and overhead related to providing compensation lands.

The project owner is responsible for all compensation lands acquisition/easement costs, including but not limited to, title and document review costs, as well as expenses incurred from other state agency reviews and overhead related to providing compensation lands to the department or approved third party; escrow fees or costs; environmental contaminants clearance; and other site clean up measures.

Verification: A minimum of three months prior to acquisition of the property, the project owner, or a third-party approved by the CPM, in consultation with CDFG and USFWS, shall submit a formal acquisition proposal to the CPM, CDFG, and USFWS describing the parcel(s) intended for purchase.

Draft agreements to delegate land acquisition to CDFG or an approved third party and agreements to manage compensation lands shall be submitted to Energy Commission staff for review and approval (in consultation with CDFG) prior to publication of the Final Staff Assessment. Such agreements shall be mutually approved and executed at least 60 days prior to start of any project-related ground disturbance activities. The project owner shall provide written verification to the CPM that the compensation lands or conservation easements have been acquired and recorded in favor of the approved recipient(s). Alternatively, before beginning project ground-disturbing activities, the project owner shall provide Security in accordance with this condition. Within 90 days after the land or easement purchase, as determined by the date on the title, the project owner shall provide the CPM with a management plan for review and approval, in consultation with CDFG, for the compensation lands and associated funds.

Within 90 days after completion of project construction, the project owner shall provide to the CPM verification that disturbance to Mojave creosote scrub habitat west of State Route 14 did not exceed 5.0 acres (for Option 1) or 5.8 acres (for Option 2), and that construction activities at the plant site and along the gas pipeline alignment did not result in impacts to Mojave creosote scrub habitat adjacent to work areas. If habitat disturbance exceeded that described in this analysis, the CPM shall notify the project owner of any additional funds required or lands that must be purchased to compensate for any additional habitat disturbances at the adjusted market value at the time of construction to acquire and manage habitat.

DESERT TORTOISE AND MOHAVE GROUND SQUIRREL COMPLIANCE VERIFICATION

BIO-12 The project owner shall provide staff, CDFG, and USFWS with reasonable access to the project site and mitigation lands under the control of the project owner and shall otherwise fully cooperate with the Energy Commission's efforts to verify the project owner's compliance with, or the effectiveness of, mitigation measures set forth in the conditions of certification. The project owner shall hold harmless the Designated Biologist, the Energy Commission and staff, and any other agencies with regulatory requirements addressed by the Energy Commission's sole permitting authority for any costs the project owner incurs in complying with the management measures, including stop work orders issued by the CPM or the Designated Biologist. The Designated Biologist shall do all of the following:

1. Notification. Notify the CPM, CDFG, and USFWS at least 14 calendar days before initiating ground-disturbing activities. Immediately notify the CPM, CDFG, and USFWS in writing if the project owner is not in compliance with any conditions of certification, including but not limited to any actual or anticipated failure to implement mitigation measures within the time periods specified in the conditions of certification. CDFG shall be notified at their Central Region Headquarters Office, 1234 E. Shaw Avenue, Fresno, CA 93710; (559) 243-4005. USFWS shall be notified at their Ventura office at 2493 Portola Road, Suite B, Ventura, CA 93003; (805) 644-1766

2. Monitoring During Grading. Remain on site daily while grubbing and grading are taking place to avoid or minimize take of listed species, to check for compliance with all impact avoidance and minimization

measures, and to check all exclusion zones to ensure that signs, stakes, and fencing are intact and that human activities are restricted in these protected zones.

3. Fence Monitoring. During construction maintain and check desert tortoise exclusion fences on a daily basis to ensure the integrity of the fence is maintained. The Designated Biologist shall be present on site to monitor construction and determine fence placement during fence installation. Fence inspections shall occur at least once per month throughout the life of the project, and more frequently after storms or other events that might affect the integrity and function of desert tortoise exclusion fences. Fence repairs shall occur within one day of detecting problems that affect the functioning of the desert tortoise exclusion fencing.

4. Monthly Compliance Inspections. Conduct compliance inspections at a minimum of once per month after clearing, grubbing, and grading are completed and submit a monthly compliance report to the CPM. All observations of listed species and their sign shall be reported to the Designated Biologist for inclusion in the monthly compliance report.

5. Annual Listed Species Status Report. No later than January 31 of every year the BSEP facility remains in operation, provide the CPM an annual Listed Species Status Report, which shall include, at a minimum: 1) a general description of the status of the project site and construction/operation activities, including actual or projected completion dates, if known; 2) a copy of the table in the BRMIMP with notes showing the current implementation status of each mitigation measure; 3) an assessment of the effectiveness of each completed or partially completed mitigation measure in minimizing and compensating for project impacts, and 4) recommendations on how effectiveness of mitigation measures might be improved.

6. Final Listed Species Mitigation Report. No later than 45 days after initiation of project operation provide the CPM a Final Listed Species Mitigation Report that shall include, at a minimum: 1) a copy of the table in the BRMIMP with notes showing when each of the mitigation measures was implemented; 2) all available information about project-related incidental take of listed species; 3) information about other project impacts on the listed species; 4) construction dates; 5) an assessment of the effectiveness of conditions of certification in minimizing and compensating for project impacts; 6) recommendations on how mitigation measures might be changed to more effectively minimize and mitigate the impacts of future projects on the listed species; and 7) any other pertinent information, including the level of take of the listed species associated with the project.

7. Notification of Injured, Dead, or Relocated Listed Species. In the event of a sighting in an active construction area (e.g., with equipment, vehicles, or workers), injury, kill, or relocation of any listed species, the CPM, CDFG,

and USFWS shall be notified immediately by phone. Notification shall occur no later than noon on the business day following the event if it occurs outside normal business hours so that the agencies can determine if further actions are required to protect listed species. Written follow-up notification via FAX or electronic communication shall be submitted to these agencies within two calendar days of the incident and include the following information as relevant:

a. Injured Desert Tortoise. If a desert tortoise is injured as a result of project-related activities during construction, the Designated Biologist shall immediately take it to a CDFG-approved wildlife rehabilitation and/or veterinarian clinic. Any veterinarian bills for such injured animals shall be paid by the project owner. Following phone notification as required above, the CPM, CDFG, and USFWS shall determine the final disposition of the injured animal, if it recovers. Written notification shall include, at a minimum, the date, time, location, circumstances of the incident, and the name of the facility where the animal was taken.

b. Desert Tortoise/Mohave Ground Squirrel Fatality. If a desert tortoise or Mohave ground squirrel is killed by project-related activities during construction or operation, or if a desert tortoise or Mohave ground squirrel is otherwise found dead, submit a written report with the same information as an injury report. These desert tortoises shall be salvaged according to guidelines described in *Salvaging Injured, Recently Dead, Ill, and Dying Wild, Free-Roaming Desert Tortoise* (Berry 2001). The project owner shall pay to have the desert tortoises transported and necropsied. The report shall include the date and time of the finding or incident.

8. Stop Work Order. The CPM may issue the project owner a written stop work order to suspend any activity related to the construction or operation of the project to prevent or remedy a violation of one or more conditions of certification (including but not limited to failure to comply with reporting, monitoring, or habitat acquisition obligations) or to prevent the illegal take of an endangered, threatened, or candidate species. The project owner shall comply with the stop work order immediately upon receipt thereof.

Verification: No later than two calendar days following the above-required notification of a sighting, kill, injury, or relocation of a listed species, the project owner shall deliver to the CPM, CDFG, and USFWS via FAX or electronic communication the written report from the Designated Biologist describing all reported incidents of the sighting, injury, kill, or relocation of a listed species, identifying who was notified and explaining when the incidents occurred. In the case of a sighting in an active construction area, the project owner shall, at the same time, submit a map (e.g., using Geographic Information Systems) depicting both the limits of construction and sighting location to the CPM, CDFG, and USFWS.

No later than January 31 of every year the BSEP facility remains in operation, provide the CPM an annual Listed Species Status Report as described above, and a summary of desert tortoise exclusion fence inspections and repairs conducted in the course of the year.

RAVEN MONITORING, MANAGEMENT, AND CONTROL PLAN

BIO-13 The project owner shall design and implement a Raven Monitoring, Management, and Control Plan (Raven Plan) that is consistent with the most current USFWS-approved raven management guidelines and that meets the approval of the USFWS, CDFG, and the Energy Commission. The Raven Plan shall: identify conditions associated with the project that might provide raven subsidies or attractants; describe management practices to avoid or minimize conditions that might increase raven numbers and predatory activities; describe control practices for ravens; address monitoring during construction and for the life of the project; and discuss reporting requirements. The project owner shall provide annual reports describing implementation of the Raven Plan for the life of the project. The Raven Plan shall also include a requirement for payment of an in-lieu fee to a third-party account established by the USFWS to support a regional raven monitoring and management plan (USFWS 2009).

Verification: At least 60 days prior to start of any project-related ground disturbance activities, the project owner shall provide the CPM, USFWS, and CDFG with the final version of the Raven Plan that has been reviewed and approved by USFWS and CDFG. The CPM shall determine the plan's acceptability within 15 days of receipt of the final plan. All modifications to the approved Raven Plan must be made only after consultation with the Energy Commission staff, USFWS, and CDFG. The project owner shall notify the CPM no less than five working days before implementing any CPM-approved modifications to the Raven Plan.

Within 30 days after completion of project construction, the project owner shall provide to the CPM for review and approval a report identifying which items of the Raven Plan have been completed, a summary of all modifications to mitigation measures made during the project's construction phase, and which items are still outstanding.

EVAPORATION POND DESIGN, MONITORING, AND MANAGEMENT PLAN

BIO-14 The project owner shall design and implement an Evaporation Pond Design, Monitoring, and Management Plan (Evaporation Pond Plan) that meets the requirements of the USFWS, RWQCB, CDFG and CPM. The Evaporation Pond Plan shall include: a discussion of the objectives of the Evaporation Pond Plan; a description of project design features such as side slope specifications, freeboard and depth requirements; avian, pond, and water quality monitoring, management actions such as bird deterrence/hazing and water level management and triggers for those management actions; and reporting requirements. Evaporation pond monitoring and reporting shall continue for the life of the project.

Verification: At least 60 days prior to start of any project-related ground disturbance activities, the project owner shall provide the CPM, USFWS, RWQCB, and CDFG with the final version of the Evaporation Pond Plan that has been reviewed and approved by the CPM in consultation with USFWS, RWQCB, and CDFG. The CPM will determine the plan's acceptability within 15 days of receipt of the final plan. All modifications to the approved Evaporation Pond Plan may be made by the CPM after consultation with USFWS, RWQCB, and CDFG. The project owner shall notify the CPM no less than five working days before implementing any CPM-approved modifications to the Evaporation Pond Plan.

Within 30 days after completion of project construction, the project owner shall provide to the CPM for review and approval a report identifying which items of the Evaporation Pond Plan have been completed, a summary of all modifications to mitigation measures made during the project's construction phase, and as-built drawings of the evaporation ponds.

PRE-CONSTRUCTION NEST SURVEYS AND IMPACT AVOIDANCE MEASURES FOR MIGRATORY BIRDS

BIO-15 Pre-construction nest surveys shall be conducted if construction activities will occur from February 1 through August 1. The Designated Biologist or Biological Monitor shall perform surveys in accordance with the following guidelines:

1. Surveys shall cover all potential nesting habitat in the project site and within 500 feet of the boundaries of the plant site and linear facilities;

2. At least two pre-construction surveys shall be conducted, separated by a minimum 10-day interval. One of the surveys needs to be conducted within the 14-day period preceding initiation of construction activity. Additional follow-up surveys may be required if periods of construction inactivity exceed three weeks in any given area, an interval during which birds may establish a nesting territory and initiate egg laying and incubation;

3. If active nests are detected during the survey, a no-disturbance buffer zone (protected area surrounding the nest, the size of which is to be determined by the Designated Biologist in consultation with CDFG and USFWS) and monitoring plan shall be developed. Nest locations shall be mapped using GPS technology and submitted, along with a weekly report stating the survey results, to the CPM; and

4. The Designated Biologist shall monitor the nest until he or she determines that nestlings have fledged and dispersed; activities that might, in the opinion of the Designated Biologist, disturb nesting activities, shall be prohibited within the buffer zone until such a determination is made.

Verification: At least 10 days prior to the start of any project-related ground disturbance activities, the project owner shall provide the CPM a letter-report describing the findings of the pre-construction nest surveys, including the time, date, and duration of the survey; identity and qualifications of the surveyor(s); and a list of species observed. If active nests are detected during the survey, the report shall include a map or aerial photo identifying the location of the nest and shall depict the boundaries of the no-disturbance buffer zone around the nest.

AMERICAN BADGER AND DESERT KIT FOX IMPACT AVOIDANCE AND MINIMIZATION MEASURES

BIO-16 To avoid direct impacts to American badgers and desert kit fox, pre-construction surveys shall be conducted for these species concurrent with the desert tortoise clearance surveys. Surveys shall be conducted as described below:

Biological Monitors shall perform pre-construction surveys for badger and kit fox dens in the project area, including areas within 250 feet of all project facilities, utility corridors, and access roads. If dens are detected each den shall be classified as inactive, potentially active, or definitely active.

Inactive dens shall be excavated by hand and backfilled to prevent reuse by badgers or kit fox. Potentially and definitely active dens shall be monitored by the Biological Monitor for three consecutive nights using a tracking medium (such as diatomaceous earth or fire clay) and/or infrared camera stations at the entrance. If no tracks are observed in the tracking medium or no photos of the target species are captured after three nights, the den shall be excavated and backfilled by hand. If tracks are observed, the den shall be progressively blocked with natural materials (rocks, dirt, sticks, and vegetation piled in front of the entrance) for the next three to five nights to discourage the badger or kit fox from continued use. After verification that the den is unoccupied it shall then be excavated and backfilled by hand to ensure that no badgers or kit fox are trapped in the den.

Verification: The project owner shall submit a report to the CPM and CDFG at least 30 days prior to the start of any project-related site disturbance activities that describes when badger and kit fox surveys were completed, observations, mitigation measures implemented, and the results of the mitigation.

BURROWING OWL IMPACT AVOIDANCE, MINIMIZATION, AND COMPENSATION MEASURES

BIO-17 The project owner shall implement the following measures to avoid and offset impacts to burrowing owls:

1. Artificial Burrow Installation. At least one year prior to construction, the project owner shall install four artificial burrows, or at least two burrows for each owl displaced by the project, in the proposed translocation area, a 14.39-acre parcel owned by Beacon Solar, LLC, (APN 469-14-011). Design of the artificial burrows shall be consistent with CDFG guidelines (CDFG 1995). The Designated Biologist shall survey the site selected for artificial burrow construction to verify that such construction will not affect desert tortoise or Mohave ground squirrel. The design of the burrows shall be approved by the CPM in consultation with CDFG and USFWS. The Designated Biologist shall survey the translocation site at least

monthly to assess use of the artificial burrows by owls, starting upon completion of artificial burrow construction and continuing for at least five years.

2. Protect Translocation Area in Perpetuity. The project owner shall provide a mechanism to protect 6 acres of the 14.39-acre translocation area in perpetuity as habitat for burrowing owls, either in fee title or as a conservation easement. The terms and conditions of this acquisition or easement shall be as described in **BIO-11**.

3. Pre-Construction Surveys. Concurrent with desert tortoise clearance surveys, the Designated Biologist shall conduct pre-construction surveys for burrowing owls within the project site and along all linear facilities in accordance with CDFG guidelines (California Burrowing Owl Consortium 1993). If burrowing owls are detected within the impact area or within 500 feet of any proposed construction activities, the Designated Biologist shall prepare a Burrowing Owl Monitoring and Mitigation Plan in consultation with CDFG. This plan shall include detailed measures to avoid and minimize impacts to burrowing owls in and near the construction areas and shall be consistent with CDFG guidance (CDFG 1995).

4. Acquire 20 Acres of Burrowing Owl Habitat. The project owner shall acquire, in fee or in easement, 20 acres of land suitable to support a resident population of burrowing owls and shall provide funding for the enhancement and long-term management of these compensation lands. The responsibilities for acquisition and management of the compensation lands may be delegated by written agreement to CDFG or to a third party, such as a non-governmental organization dedicated to Mojave Desert habitat conservation, subject to approval by the CPM, in consultation with CDFG and USFWS prior to land acquisition or management activities. Additional funds shall be based on the adjusted market value of compensation lands at the time of construction to acquire and manage habitat. Agreements to delegate land acquisition to CDFG or an approved third party and to manage compensation lands shall be implemented within 12 months of the Energy Commission’s decision.

   a. Burrowing Owl Mitigation Criteria. The terms and conditions of this acquisition or easement shall be as described in **BIO-11**, with the additional criteria to include: 1) the 20 acres of mitigation land must provide suitable habitat for burrowing owls, and 2) the acquisition lands must either currently support burrowing owls or be no farther than 5 miles from an active burrowing owl nesting territory. The 20 acres of burrowing owl mitigation lands may be included with the 115 acres (117.4 acres for Option 2) of desert tortoise and Mohave ground squirrel mitigation lands ONLY if these two burrowing owl criteria are met.

   b. Security. If the 20 acres of burrowing owl mitigation land is separate from the 115 acres (117.4 for Option 2), the project owner or an approved third party shall complete acquisition of the proposed compensation lands prior to initiating ground-disturbing project activities. Alternatively, financial assurance can be provided to the CPM in the form of an irrevocable letter of credit, a pledged savings account or another form of security ("Security") prior to initiating ground-disturbing project activities. Prior to submittal to the CPM, the Security shall be approved by the CPM, in consultation with CDFG, to ensure funding in an amount determined by a Property Analysis Record (PAR) or PAR-like analysis of the proposed compensation lands.

Verification: At least six months prior to initiation of ground-disturbing construction activities the project owner shall provide a report to CDFG, USFWS, and the CPM documenting completion of artificial burrow construction. Every month thereafter for a period of five years the Designated Biologist shall submit a report describing use of the passive relocation site by burrowing owl.

At least 30 days prior to the start of any project-related site disturbance activities the Designated Biologist shall provide to CDFG, USFWS, and the CPM the Burrowing Owl Monitoring and Mitigation Plan described above and shall report monthly to CDFG, USFWS, and the CPM for the duration of construction on the implementation of avoidance and minimization measures described in the plan. Within 30 days after completion of construction the project owner shall provide to the CDFG and CPM a written construction termination report identifying how measures have been completed.

Prior to start of any project-related ground disturbance activities the project owner shall provide written verification to the CPM that the 20 acres of compensation lands or conservation easements have been acquired and recorded in favor of the approved easement holder(s). Alternatively, before beginning project ground-disturbing activities, the project owner shall provide Security to the CPM in accordance with this condition. Within 90 days of the land or easement purchase, as determined by the date on the title, the project owner shall provide the CPM with a management plan for review and approval, in consultation with CDFG, for the compensation lands and associated funds.

STREAMBED IMPACT MINIMIZATION AND COMPENSATION MEASURES

BIO-18 The project owner shall prepare and implement a Desert Wash Mitigation and Monitoring Plan (Plan) to compensate for permanent impacts to 10,900 feet of Pine Tree Creek (loss of 14.96 acres of state waters) and 2,150 feet of an unnamed desert wash (loss of 1.04 acres of state waters). The overall objectives of the Plan shall be to replicate the hydrological and biological functions of the drainages that will be eliminated by the project. The specific elements of the Plan cannot be developed until the channel design and bank stabilization methods have been finalized, which in turn depends on the results of hydrological and hydraulic studies currently underway. The project owner shall implement the following measures:

1. Proposed Channel Requirements:. The proposed channel design shall address at least the following requirements:
   a. The proposed channel shall be designed to be geomorphically stable and to maintain existing hydrological connections and levels of sediment transport;

   b. The channel stabilization approach shall include bioengineering methods using native plant species for bank protection if the hydraulic analysis of the channel indicates that such methods are viable;

   c. The proposed channel design shall provide conditions that would support recruitment and maintenance of native vegetation, provide wildlife habitat, and maintain the biological functions and values of a natural desert wash ecosystem;

   d. The proposed channel shall be designed, constructed and maintained such that it would not create a movement barrier or hazard for desert tortoise or other wildlife; and

   e. Monitoring and maintenance of the channel and mitigation/revegetation areas shall continue for the life of the project.

2. Review and Submittal of Plan: Prior to publication of the Final Staff Assessment the project owner shall submit to Energy Commission Staff and CDFG a draft Desert Wash Mitigation and Monitoring Plan that incorporates the final channel design, bank stabilization recommendations and proposed maintenance.

3. Equipment Laydown Plan: The project owner shall develop an engineered plan for the proposed equipment laydown area within the existing wash which describes protective structures, procedures for moving equipment, fuels and materials, and plan for conveyance of stormflows, during a rainfall event. Prior to initiation of any project activities in jurisdictional areas and no later than 60 days after publication of the Energy Commission Decision, the project owner shall submit this plan for review and approval by the CPM in consultation with CDFG.

4. Right of Access and Review for Compliance Monitoring: The CPM reserves the right to enter the project site or allow CDFG to enter the project site at any time to ensure compliance with these conditions. The project owner herein grants to the CPM and to CDFG employees and/or their representatives the right to enter the project site at any time, to ensure compliance with the terms and conditions and/or to determine the impacts of storm events, maintenance activities, or other actions that might affect the restoration and revegetation efforts. The CPM and CDFG

may, at the CPM's discretion, review relevant documents maintained by the operator, interview the operator's employees and agents, inspect the work site, and take other actions to assess compliance with or effectiveness of mitigation measures.

5. Security for Implementation of Mitigation: A security in the form of an irrevocable letter of credit, pledged savings account, or certificate of deposit for the amount of all mitigation measures pursuant to this condition of certification shall be submitted to, and approved by, the CPM, in consultation with CDFG, prior to commencing project activities within waters of the state. This amount shall be based on an estimate that reflects all costs associated with creating the engineered channel, and shall be submitted to CDFG for review and to the CPM for approval within 60 days of the Energy Commission Decision's publication and prior to commencing project activities within waters of the state. The security shall be approved by the CPM, in consultation with CDFG's legal advisors, prior to its execution, and shall allow the CPM at its discretion to recover funds immediately if the CPM, in consultation with CDFG, determines there has been a default.

6. Reporting of Special-Status Species: If any special-status species are observed on or in proximity to the project site, or during project surveys, the project owner shall submit California Natural Diversity Data Base (CNDDB) forms and maps to the CNDDB within five working days of the sightings and provide the regional CDFG office with copies of the CNDDB forms and survey maps. The CNDDB form is available online at: www.dfg.ca.gov/whdab/pdfs/natspec.pdf. This information shall be mailed within five days to: California Department of Fish and Game, Natural Diversity Data Base, 1807 13th Street, Suite 202, Sacramento, CA 95814, (916) 324-3812. A copy of this information shall also be mailed within five days to CDFG and the CPM.

7. Notification: The project owner shall notify the CPM and CDFG, in writing, at least five days prior to initiation of project activities in jurisdictional areas as noted and at least five days prior to completion of project activities in jurisdictional areas. The project owner shall notify the CPM and CDFG of any change of conditions to the project, the jurisdictional impacts, or the mitigation efforts, if the conditions at the site of a proposed project change in a manner which changes risk to biological resources that may be substantially adversely affected by the proposed project. The notifying report shall be provided to the CPM and CDFG no later than seven days after the change of conditions is identified. As used here, change of condition refers to the process, procedures, and methods of operation of a project; the biological and physical characteristics of a project area; or the

laws or regulations pertinent to the project as defined below. A copy of the notifying change of conditions report shall be included in the annual reports.

a. Biological Conditions: a change in biological conditions includes, but is not limited to, the following: 1) the presence of biological resources within or adjacent to the project area, whether native or non-native, not previously known to occur in the area; or 2) the presence of biological resources within or adjacent to the project area, whether native or non-native, the status of which has changed to endangered, rare, or threatened, as defined in section 15380 of Title 14 of the California Code of Regulations.

b. Physical Conditions: a change in physical conditions includes, but is not limited to, the following: 1) a change in the morphology of a river, stream, or lake, such as the lowering of a bed or scouring of a bank, or changes in stream form and configuration caused by storm events; 2) the movement of a river or stream channel to a different location; 3) a reduction of or other change in vegetation on the bed, channel, or bank of a drainage, or 4) changes to the hydrologic regime such as fluctuations in the timing or volume of water flows in a river or stream.

c. Legal Conditions: a change in legal conditions includes, but is not limited to, a change in Regulations, Statutory Law, a Judicial or Court decision, or the listing of a species, the status of which has changed to endangered, rare, or threatened, as defined in section 15380 of Title 14 of the California Code of Regulations.

8. Code of Regulations. The project owner shall provide a copy of the Energy Commission Decision to all contractors, subcontractors, and the applicant's project supervisors. Copies shall be readily available at work sites at all times during periods of active work and must be presented to any CDFG personnel or personnel from another agency upon demand. The CPM reserves the right to issue a stop work order or allow CDFG to issue a stop work order after giving notice to the project owner and the CPM, if the CPM in consultation with CDFG, determines that the project owner has breached any of the terms or conditions or for other reasons, including but not limited to the following:

   a. The information provided by the applicant regarding streambed alteration is incomplete or inaccurate;

   b. New information becomes available that was not known to it in preparing the terms and conditions;

   c. The project or project activities as described in the Final Staff Assessment have changed; or

d. The conditions affecting biological resources changed or the CPM, in consultation with CDFG, determines that project activities will result in a substantial adverse effect on the environment.

9. Stop Work Provisions: The following provisions are not subject to amendment or arbitration. CDFG may issue a stop work order at any time in consultation with the CPM if CDFG determines that the project owner or any person acting on its behalf, including its agents, officers, and employees, agents, representatives, or contractors and subcontractors, is not in compliance with these terms and conditions, as provided herein.

   a. The CPM shall, in advance, provide the project owner written notice that it intends to suspend work. The notice shall state the reasons for the proposed suspension and provide the project owner an opportunity to correct any deficiency. In the interim, the project owner shall comply with any instructions in the notice. Within seven days of receiving a suspension notice, the project owner shall notify CDFG and the CPM in writing by certified or registered mail either that it will correct any deficiency, and state how it intends to do so, or that it objects to the suspension, and state the reasons for the objection.

   b. If the project owner notifies the CPM and CDFG that it will correct the deficiencies identified in the suspension notice, within seven days of receiving the project owner's response, the CPM, in consultation with CDFG, shall direct the project owner verbally or in writing on how to proceed to correct the deficiencies and the date by which the deficiencies must be corrected.

   c. If the CPM, in consultation with CDFG, determines in consultation with the CPM that the deficiencies have been corrected in accordance with its instructions to the project owner, the CPM shall inform the project owner in writing that it no longer intends to suspend, in which case the project owner may restart any ceased activity.

   d. If the CPM determines that the deficiencies have not been corrected in accordance with its instructions to the project owner, the CPM shall consult with CDFG to determine further actions.

   e. If the project owner notifies the CPM that it objects to the suspension, within 14 days of receiving the project owner's response, the CPM shall notify the project owner in writing of its decision regarding the proposed suspension.

   f. If the CPM, in consultation with CDFG, decides not to suspend, the CPM, in consultation with CDFG, shall provide a scope of work to correct the deficiencies.

   g. After correcting the deficiencies and receiving the CPM's approval to proceed with the original scope, the project owner may restart any ceased activity.

h. If the CPM, in consultation with CDFG, decides instead to suspend, the project owner shall cease all work immediately upon receipt of the decision, unless CDFG and the CPM specifies otherwise.

10. Construction Schedule: Pine Tree Creek and the unnamed desert wash shall not be altered until the new channel is constructed and ready to accept stormwater flows.

11. Best Management Practices: The applicant shall also comply with the following conditions:

    a. The project owner shall not allow water containing mud, silt, or other pollutants from grading, aggregate washing, or other activities to enter a lake or flowing stream or be placed in locations that may be subjected to high storm flows.

    b. The project owner shall comply with all litter and pollution laws. All contractors, subcontractors, and employees shall also obey these laws, and it shall be the responsibility of the operator to ensure compliance.

    c. Spoil sites shall not be located within a drainage or locations that may be subjected to high storm flows, where spoil shall be washed back into a drainage or lake.

    d. Raw cement/concrete or washings thereof, asphalt, paint or other coating material, oil or other petroleum products, or any other substances that could be hazardous to vegetation or wildlife resources, resulting from project-related activities, shall be prevented from contaminating the soil and/or entering waters of the state. These materials, placed within or where they may enter a drainage or lake, by project owner or any party working under contract or with the permission of the project owner shall be removed immediately.

    e. No broken concrete, debris, soil, silt, sand, bark, slash, sawdust, rubbish, cement or concrete or washings thereof, oil or petroleum products or other organic or earthen material from any construction or associated activity of whatever nature shall be allowed to enter into, or placed where it may be washed by rainfall or runoff into, waters of the state.

    f. When operations are completed, any excess materials or debris shall be removed from the work area. No rubbish shall be deposited within 150 feet of the high water mark of any drainage.

    g. No equipment maintenance shall occur within or near any stream channel where petroleum products or other pollutants from the equipment may enter these areas under any flow.

12. Acquire Off-Site Desert Wash: The project owner shall acquire, in fee or in easement, a parcel of land that includes a desert wash with at least 16 acres of state jurisdictional waters. The responsibilities for acquisition and management of the compensation lands may be delegated by written agreement to CDFG or to a third party, such as a non-governmental organization dedicated to Mojave Desert habitat conservation, subject to approval by the CPM, in consultation with CDFG and RWQCB prior to land acquisition or management activities. Additional funds shall be based on the adjusted market value of compensation lands at the time of construction to acquire and manage habitat. Agreements to delegate land acquisition to CDFG or an approved third party and to manage compensation lands shall be implemented within 12 months of the Energy Commission's decision. The terms and conditions of this acquisition or easement shall be as described in **BIO-11**, with the additional criteria that the desert wash mitigation lands: 1) include at least 16 acres of state jurisdictional waters; 2) be characterized by similar soil permeability and hydrological and biological functions as the impacted wash; and 3) be within the same watershed as the impacted wash. The desert wash mitigation lands may be included with the 115 acres (117.4 acres for Option 2) of desert tortoise and Mohave ground squirrel mitigation lands ONLY if the above three criteria are met.

Verification: No fewer than 30 days prior to the start of any site or related facilities mobilization activities, the project owner shall implement the mitigation measures described above. No fewer than 30 days prior to the start of work potentially affecting waters of the state, the project owner shall provide written verification (i.e., through incorporation into the BRMIMP) to the CPM that the above best management practices will be implemented and provide a discussion of work in waters of the state in Compliance Reports for the duration of the project. Compliance reports shall be monthly for the first five years following construction of the re-routed wash, and thereafter shall be submitted every six months.

No fewer than 30 days prior to the start of work potentially affecting waters of the state, and no later than 60 days after publication of the Energy Commission Decision the project owner shall submit a final Desert Wash Mitigation and Monitoring Plan that has been reviewed and approved by the CPM in consultation with CDFG.

CLOSURE PLAN MEASURES

BIO-19 The project owner shall implement and incorporate into the facility closure plan measures to address the local biological resources related to facility closure. A funding mechanism shall be developed in consultation with the Energy Commission staff to ensure sufficient funds are available for revegetation, reclamation, and decommissioning. The facility closure plan shall address biological resources-related mitigation measures. In addition to these measures, the plan must include the following:

1. removal of transmission conductors when they are no longer used and useful;

2. removal of all above-ground and subsurface power plant site facilities and related facilities;

3. methods for restoring wildlife habitat and promoting the re-establishment of native plant and wildlife species;

4. revegetation of the project site and other disturbed areas utilizing appropriate seed mixture;

5. a cost estimate to complete closure-related activities.

In addition, the project owner shall secure funding to ensure implementation of the plan and provide to the CPM written evidence of the dedicated funding mechanism(s).

Verification: Prior to initiating ground-disturbing project activities the project owner shall provide financial assurances to the CPM to guarantee that an adequate level of funding will be available to implement decommissioning and closure activities described above. The financial assurances may be in the form of an irrevocable letter of credit, a pledged savings account or another form of security.

At least 12 months prior to commencement of planned closure activities, the project owner shall address all biological resources-related issues associated with facility closure, and provide final measures, in a Biological Resources Element. The draft planned permanent or unplanned closure measures shall be submitted to the CPM for comment by staff, CDFG, and USFWS. After revision, final measures shall comprise the Biological Resources Element, which shall include the items listed above as well as written evidence of the dedicated funding mechanism(s) for these measures. The final Biological Resources Element shall become part of the facility closure plan, which is submitted to the CPM within 90 days of the permanent closure or another period of time agreed to by the CPM.

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 (see **Compliance** Conditions of Certification).

Upon facility closure, the project owner shall implement measures in the Biological Resources Element and provide written status updates on all closure activities to the CPM at a frequency determined by the CPM.

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The tn: 00000 in the references below indicates the transaction number under which the item is catalogued in the Energy Commission's Docket Unit. The transaction number allows for quicker search and retrieval of individual items docketed for a case or used for ease of reference and retrieval of exhibits cited in briefs and used at Evidentiary Hearings.

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CULTURAL RESOURCES

Michael D. McGuirt, Amanda Blosser, and Beverly E. Bastian

SUMMARY OF CONCLUSIONS

Staff concludes that the Beacon Solar Energy Project (BSEP) would have significant direct impacts on surface and subsurface prehistoric archaeological resources. The proposed project may also have such impacts on historical archaeological resources. The complete scope of these impacts is, however, incompletely known at present. A critical source of information on the physical contexts of the archaeological resources in the project area, a geoarchaeology study (see "Geoarchaeology Study" subsection, below), is currently underway. Conditions of certification to mitigate the complete complement of the significant direct impacts of the proposed project on historical resources will be proposed in the Final Staff Assessment (FSA), upon the receipt of the results of the geoarchaeology study and further consultation with the applicant.

The adoption and implementation of staff's proposed Conditions of Certification **CUL-1** through **CUL-8** ensure that the applicant would be able to respond quickly and effectively in the event that archaeological sites are found on the surface of the project area or buried beneath it during construction-related ground disturbance. These conditions are draft proposals and may be modified in response to additional information that the applicant may provide prior to the publication of the FSA.

INTRODUCTION

This cultural resources assessment identifies the potential impacts of the BSEP to cultural resources. Cultural resources are defined under state law as buildings, sites, structures, objects, and historic districts. Four kinds of cultural resources are considered in this assessment, prehistoric and historical archaeological sites, ethnographic resources, and built-environment resources.

Prehistoric archaeological sites are associated with the Native American occupation and use of California prior to prolonged European contact. They typically include deposits of artifacts and organic debris, constructed features used to prepare, store, and discard the implements and food resources that helped to sustain daily life, structural ruins, rock art, trails, and other traces of Native American behavior. For the purpose of the present analysis, Energy Commission staff marks the onset of the prehistoric period at approximately 12,000 years ago, the most widely agreed upon date among scholars of the early prehistory of the Western Hemisphere. The prehistoric period in California extends through 1769, when the Spanish established the first missions in the region.

Ethnographic resources represent the heritage of a particular ethnic or cultural group, such as Native Americans or African, European, or Asian immigrants. They may include traditional resource-collecting areas, ceremonial sites, value-imbued landscape features, cemeteries, shrines, or ethnic neighborhoods and structures.

Historical archaeological sites and built-environment resources are typically associated with the non-Native American exploration and settlement of California and the beginning of a written historical record for the state. They may include archaeological deposits, sites, structures, traveled ways, artifacts, or other evidence of human activity. Under federal and state statute and regulation, cultural resources must be greater than fifty years old to be considered of potential historic significance. A resource less than fifty years of age may be historically significant if the resource possesses exceptional values.

For the BSEP, staff provides an overview of the environmental setting and history of the project area, an inventory of the cultural resources identified in the project vicinity, and an analysis of the potential impacts from the proposed project using criteria from the California Environmental Quality Act (CEQA). The primary concern is to ensure that all potential impacts are identified and that conditions are set forth that ensure that potentially significant impacts are appropriately mitigated.

If cultural resources are identified, staff determines whether there may be a project-related impact to them. If the cultural resources cannot be avoided, staff determines whether any of the affected resources are eligible for the California Register of Historical Resources (CRHR). If affected resources are eligible for the register, staff recommends mitigation measures that ensure that impacts to the identified cultural resources are reduced to less-than-significant levels.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

Projects licensed by the Energy Commission are reviewed to ensure compliance with all applicable laws. For the present analysis the applicable laws are primarily state laws. Although the Energy Commission has exclusive permitting authority over BSEP, the Energy Commission typically ensures compliance with all applicable laws, ordinances, regulations, standards, plans, and policies.

CULTURAL RESOURCES TABLE 1
Laws, Ordinances, Regulations, and Standards

Applicable Law	Description
State	
Public Resources Code 5097.98 (b) and (e)	Requires a landowner on whose property Native American human remains are found to limit further development activity in the vicinity until he/she confers with the Native American Heritage Commission-identified Most Likely Descendents (MLDs) to consider treatment options. In the absence of MLDs or of a treatment acceptable to all parties, the landowner is required to reinter the remains elsewhere on the property in a location not subject to further disturbance.
California Health and Safety Code, Section 7050.5	This code makes it a misdemeanor to disturb or remove human remains found outside a cemetery. This code also requires a project owner to halt construction if human remains are discovered and to contact the county coroner.
Local	
Kern County General Plan, 2007 Land Use, Open Space, and Conservation Element: Policy 25 and Implementation Measures K–L, N–O	1.10.3: Archaeological, Paleontological, Cultural, and Historical Preservation Policy 25: The County will promote the preservation of cultural and historic resources which provide ties with the past and constitute a heritage value to residents and visitors. Implementation Measure K: Coordinate with the California State University, Bakersfield's Archaeology Inventory Center. Implementation Measure L: The County shall address archaeological and historical resources for discretionary projects in accordance with the California Environmental Quality Act (CEQA). Implementation Measure N: The County shall develop a list of Native American organizations and individuals who desire to be notified of proposed discretionary projects. This notification will be accomplished through the established procedures for discretionary projects and CEQA documents. Implementation Measure O: On a project-specific basis, the County Planning Department shall evaluate the necessity for the involvement of a qualified Native American monitor for grading or other construction activities on discretionary projects that are subject to a CEQA document.

SETTING

Information provided regarding the setting of the proposed project places it in geographical and geological contexts and specifies the technical description of the project. Additionally, the archaeological, ethnographic, and historical backgrounds provide the contexts for the evaluation of the historical significance of any identified cultural resources within the project area of analysis.

REGIONAL SETTING

The proposed BSEP project area is located in eastern Kern County within the northern Fremont Valley. The valley is surrounded by the El Paso Mountains to the north, the Rand Mountains to the east, the southern Sierra Nevada and Tehachapi Mountains to the west, and the Rosamond Hills and Antelope Valley to the south (Apple and Glenny 2008). The site is situated within a closed basin, with Koehn Dry Lake located approximately 6 miles to the east-northeast. Cottonwood and Cache Creeks, and an unnamed wash are the three major drainages that flow into this basin. The nearest seismic features are the Garlock Fault to the north and the San Andreas Fault to the west (Apple and Glenny 2008). The predominant vegetation type on the floor of Fremont Valley is Mojave creosote bush scrub (BS 2008a, p. 5.4-6).

PROJECT, SITE, AND VICINITY DESCRIPTION

The proposed BSEP is a concentrated solar electric generating facility (BS 2008a, p. 1-1). It would have a nominal electrical output of 250 megawatts (MW). Of the 2,012-acre proposed plant site parcel, the power block area and the solar thermal field would occupy approximately 1,240 acres, with the rest of the support facilities occupying the remaining approximately 770 acres. The proposed plant site is within a region that is primarily undeveloped, but, as late as the mid-1980s, it was used for agricultural purposes and, as a result, has been heavily disturbed (BS 2008a, pp. 1-3; 2-3).

The proposed facility would be located in eastern Kern County, within the western Mojave Desert, approximately 4 miles north-northwest of California City, approximately 15 miles north of the City of Mojave, and approximately 24 miles northeast of the City of Tehachapi (BS 2008a, p. 1-2). Red Rock Canyon State Park is approximately 4 miles to the north, and Koehn Dry Lake is located approximately 6 miles to the east-northeast. The proposed facility would be accessed from State Route (SR) 14.

The proposed project site is relatively flat, with the current elevation ranging from approximately 2,025 to 2,220 feet above mean sea level (AMSL) (BS 2008a, p. 1-3). During proposed grading and stream realignment activities at the plant site, cuts would range from a few feet to as deep as 9.7 feet below the current ground surface (DB 2008a, Response to Data Request No. 33). The total soil volume to be moved to level the site would be approximately 5,160,000 cubic yards (BS 2008a, p. 2-26). The final elevation within the power block is anticipated to range from approximately 2,050 to 2,250 feet AMSL.

The proposed BSEP would consist of several components: a power block area (solar steam generator (SSG) heat exchangers, steam turbine generator (STG) and condenser, 230-kV on-site switchyard, wet-cooling tower, natural gas-fired auxiliary boilers, and water storage tanks); a solar collector field; a new 17.6-mile-long, 8-inch-diameter natural gas pipeline; a new 3.5-mile-long 230-kV transmission line (two routing options proposed); three 8.3-acre evaporation ponds; a control room and warehouse;

an administration building; bioremediation/landfarm areas; existing groundwater wells for water supply; a dry wash realignment, and an access road extending from SR 14 (BS 2008a, pp. 2-4–2-5).

To tie into the Los Angeles Department of Water and Power's (LADWP) Barren Ridge Switching Station, the applicant has proposed two 230-kV transmission line routing options. The two routes are about the same length, and both exit the plant along the plant access road. From that point, Option 1 takes a jogging southwesterly course, crossing the existing Union Pacific railroad and SR 14, to reach the right-of-way (ROW) of LADWP's Inyo-Barren Ridge 230-kV transmission line, next to which it runs southwest (parallel on the east side of the ROW) to connect into Barren Ridge Switching Station. Option 2 also takes a southwesterly course from the plant access road, but turns directly west, crossing the existing Union Pacific railroad and SR 14, until it reaches the Inyo-Barren Ridge 230 kV transmission line's ROW at a more northerly point than Option 1. At that intersection, a new switching station would be built, and the Option 2 transmission line would terminate there. An additional new 230-kV transmission line would be constructed from the new switching station to LADWP's Barren Ridge Switching Station (BS 2008a, pp. 2-29–2-30).

Environmental Setting

The proposed project area is a roughly 2,012-acre expanse of what is today an arid bajada[1]. The environment of the bajada has changed through time causing concomitant shifts in the mosaic of natural resources available on it and adjacent landforms. Human use of the proposed project area over the past several thousand years may partly reflect local changes in the natural resource base. To more reliably assess the likelihood that archaeological deposits representing such use may be present, it is important to consider the historical character of local climate change, or the paleoclimate, and the effects of the paleoclimate on the physical development of the bajada and its ecology.

Regional Climatic and Environmental History

The proposed BSEP site is located in the western Mojave Desert, within the Fremont Valley of Kern County, near the southern end of the Sierra Nevada mountain range, which rises just to the west of the project area. It is within the rain shadow of this range, only averaging three inches of rainfall per year. Koehn Lake is approximately six miles to the northeast of the project site, and is dry, except in the aftermath of the occasional storm. A desert wash, Pine Tree Creek, extends through the project area (Apple and Glenny 2008, pp. 11–14).

During prehistory, this region fluctuated between cool-and-moist and warm-and-arid periods of climate. During the Pleistocene (25,000–10,000 B.P.), the climate was relatively cool and moist, with the region covered with pluvial lakes and associated lacustrine[2] resources. Toward the terminal Pleistocene, the climate resembled that of today. At the beginning of the Holocene, conditions became warmer in the desert valleys, with less precipitation occurring in the adjacent mountains. The early Holocene

[1] An alluvial plain formed as a result of lateral growth of adjacent alluvial fans until they finally coalesce to form a continuous inclined deposit along a mountain front.

[2] Of or relating to lakes.

(10,000–8,000 B.P.) witnessed this rise in temperature and aridity; however, the climate was still slightly cooler and moister than the present (Sutton 1996, p. 231). During the middle Holocene (8,000–3,000 B.P.), the climate became much warmer and drier, with an even lower incidence of precipitation. Finally, with the late Holocene (3,000–present), it became moderately cooler and wetter, with marked episodes of drought.

Geology

The discussion in the FSA of the geology of the proposed project area will consider the structural and historical geology of the project area and the project vicinity.

Geomorphology

The discussion in the FSA of the geomorphology of the proposed project area will consider how and when the underlying bajada may have developed, and will help provide the physical contexts to assess whether physical remains from the past human use of former land surfaces on the bajada may be present as archaeological deposits. Staff will develop discussions of process and historical geomorphology on the basis of the results of a geoarchaeology study that the applicant is presently conducting (see “Geoarchaeology Study” subsection, below).

Prehistoric Setting

The prehistory of the western Mojave Desert is the narrative of how human populations have adapted to marked fluctuations in the local environment over the course of at least the last 12,000 years. The archaeological remains of the region’s prehistory are relatively scarce. Sparse scatters of stone tools and chipped stone tool manufacturing debris, and isolated artifacts, resources that typically yield information of marginal value, account for 40 to 60 percent of the archaeological remains found in the Mojave and Colorado Deserts. A relative paucity of intact buried archaeological deposits contributes further to the dearth of information on the prehistory of the region (Lyneis and Macko 1986, p. 52). The availability of water and the location of high-value resource patches in otherwise unproductive habitats appear to influence the distribution of the archaeological sites that are on the desert landscape (Lyneis and Macko 1986, p. 57; Sutton, et al., 2007, p. 230). The broad trajectory of cultural development in the Mojave Desert appears to be a steady decline in residential mobility as local populations come to occupy increasingly larger valley or basin-bottom base camps, in a few preferred locations, over longer periods of time, rather than working out of temporary camps in particularly productive environmental zones (Bamforth 1990, p. 74).

Over the past seven decades, Mojave Desert archaeologists have developed and refined a broad sequence of approximately six artifact groups or assemblages, each with distinctive types of stone projectiles, that represent the material record of the peoples who once lived in the proposed project area (Bamforth 1990, p. 72; Campbell 1936; Lyneis 1982; Rogers 1939; Sutton, et al., 2007; Warren 1984; Warren and Crabtree 1986).

Terminal Pleistocene Period (Prior to 10,000 B.C.)

Evidence for a Paleo-Indian occupation in the western Mojave Desert has come in the form of fluted points, generally considered to represent the Clovis complex (Sutton, et al., 2007, pp. 233–234). It should be noted, however, that not every fluted point can necessarily be attributed to Clovis, and that the western Mojave Desert finds could be associated with later cultures using a similar technology. Work in the China Lake basin drainage, located in Indian Wells Valley to the north; and in the Lake Thompson basin drainage, located in the Antelope Valley to the south, have yielded these points. Glennan discovered an obsidian isolate on the slope of the El Paso Mountains, described as “a lanceolate-shaped point with a concave base.” He noted, however, that he considered the point to be “a Folsom-like type” (Glennan 1987; Rondeau, et al., 2007). At present, no evidence of the Clovis complex has been discovered within the Fremont Valley**.**

During this period, it has been suggested that highly mobile groups relied considerably upon lacustrine resources (Apple and Glenny 2008, p. 15). These patterns of subsistence and settlement have been collectively described as the Western Pluvial Lakes Tradition (WPLT) (Moratto 1984, pp. 90–103). This pattern has also been demonstrated throughout the western Great Basin, continuing briefly into the Early Holocene.

Early Holocene

The Lake Mojave complex is the pattern characteristic of this period, dating from approximately 8,000–6,000 cal (calibrated radiocarbon years) B.C. (Sutton, et al., 2007, p. 234). This complex is marked by projectile points of the Lake Mojave and Silver Lake types. The assemblages can also generally contain bifaces, steep-edged unifaces, and crescents in quantity, with some cobble-core tools and ground stone tools also represented.

During the Early Holocene, the pluvial lakes began to slowly recede, with groups adapting to the changing environment (Sutton, et al., 2007). Archaeological evidence indicates that lacustrine resources around these lake basins continued to be exploited, but evidence of groups obtaining other resources from beyond the lake basins, such as the procurement of lagomorphs, rodents, and certain reptiles, has also been reported from work at Fort Irwin (Sutton, et al., 2007; Basgall 1993; Douglas, et al., 1988).

Middle Holocene

For the Middle Holocene, the Pinto complex has become the widely accepted cultural complex for this region (Sutton, et al., 2007, p. 238). Archaeologists have generally accepted that the Pinto complex began just after the Lake Mojave complex and ended at approximately 3,000 cal B.C. Some, however, argue that the Lake Mojave and the Pinto complexes overlap, with the Pinto complex being introduced toward the end of the Early Holocene.

Artifacts identified with this complex include stemmed, indented-base Pinto series projectile points, probably used as thrusting spears rather than darts (Sutton, et al., 2007, p. 238). There is a dramatic increase in the presence of ground stone tools during this time period, with evidence of these implements in almost every Pinto site that has been identified. The procurement of faunal resources appears to be much the same in the Middle Holocene as in the Early Holocene, with a slight increase in small fauna, and with artiodactyls (deer and mountain sheep) decreasing (Sutton, et al., 2007, p. 238).

Pinto complex sites have been found in varying topographic and environmental zones, including pluvial lake basins, springs/seeps, streams, and within upland areas (Sutton, et al., 2007, p. 238). The dramatic increase in ground stone implements suggests that access to plant foodstuffs was probably of high importance for the selection of habitation.

The scarcity of sites in the western Mojave Desert representing the period ca. 3,000–2,000 cal B.C. indicates that there may have been “an occupational hiatus” at this time (Sutton, et al., 2007, p. 241), or that population density in the region was low. This may have been due to the climate being much hotter and drier towards the end of the Middle Holocene.

Late Holocene

The Gypsum complex appeared during the earliest part of this period, from 2,000 cal B.C.–cal A.D. 200 (Sutton, et al., 2007, p. 241). During this time, the climate became wetter and cooler than during the previous period. Artifacts from the Gypsum complex are represented by Elko series corner-notched points; Humboldt series, concave base points; and well-shouldered, contracting-stemmed, Gypsum series points (Sutton, et al., 2007, p. 241).

The Rose Spring complex followed the Gypsum complex, appearing in the period cal A.D. 200–1100, the time during which the bow and arrow were introduced. Archaeological evidence from this complex suggests demonstrates a drastic change in artifact assemblages and suggests a dramatic increase in the population, evidenced by more substantial middens (Sutton, et al., 2007, p. 241). Artifacts from this complex include Eastgate and Rose Spring series projectile points, drills, bone awls, milling implements, marine shell and other ornaments, and evidence the heavy exploitation of obsidian during this period.

According to Sutton (1996) and Gardner (2006), circumstantial evidence suggests that the lake levels at Koehn Lake may have increased after cal A.D. 1 (Sutton, et al., 2007, p. 241). Evidence from the Koehn Lake Site (CA-KER-875) in the form of burned juniper may imply that a juniper woodland habitat may have been in the area. The Medieval Climatic Anomaly (MCA) occurred sometime within the middle of the Rose Spring complex (Sutton, et al., 2007, p. 242). Lakes began to desiccate, with settlement patterns changing, as a result.

The Late Prehistoric began in 1000 A.D. and ended at European contact. During this period, populations decreased; however, new technologies were developing and several new cultural complexes appeared, most likely developing into the ethnographic groups of the region (Sutton, et al., 2007, p. 242). The marker artifacts of this period include Desert series projectile points (Desert Side-notched and Cottonwood points), ceramics, shell beads, and mortars and pestles (Warren and Crabtree, 1986; Apple and Glenny 2008, p. 17; Sutton 1991, p. 19). The prolific use of obsidian, seen during the Rose Spring complex, declined in this period (Sutton, et al., 2007, p. 242).

Ethnographic Setting

The Kawaiisu were the Native American group known ethnographically to have occupied the project area. According to Sutton, Kawaiisu territory was composed of a big portion of the western Mojave Desert, with their territory also branching into the Tehachapi Mountains near the Tehachapi Pass and extending north into the southern Sierra Nevada near the Kern River (Sutton 1991, p. 11). It should be noted, however, that during historic times, the Kawaiisu occupied the desert floor only ephemerally, spending most of the year in the higher elevations. The Kitanemuk may have frequented the Fremont Valley, as well, since the southern Tehachapi Mountains and the Antelope Valley, just to the south of the Fremont Valley, were part of the territory they traditionally claimed (Sutton 1991, pp. 11, 15).

The Kawaiisu language is part of the Southern Numic branch of the Northern Uto-Aztecan family (Sutton 1991, p. 11), making it related linguistically to many groups in the Basin and Range region. Their population at the time of contact with the Spanish has been estimated at 500 (Kroeber 1925, p. 605).

The Kawaiisu were hunter-gatherers who did not practice agriculture, but, did, however, prune tobacco plants to refine them. They also burned wild seed fields to increase plant production. The Kawaiisu exploited at least 233 plant taxa, including acorns (*Quercus* spp.), pinyon (*Pinus monophylla*), and yucca, among others (Sutton 1991, p. 13). Faunal resources included deer (*Odocoileus hemionus*), pronghorn (*Antilocapra americana*), chuckwalla (*Sauromalus obesus*), and rabbits (most likely *Lepus californicus*), which they took by means of communal drives. The Kawaiisu also procured rodents, some birds, such as quail (cf. *Oreortyx pictus*), and some insects (Sutton 1991, p. 14).

Funerary practices among the Kawaiisu were initiated by burning the deceased individual's house and possessions (Sutton 1988, p. 19). Then the body, "wrapped in a tule mat, was usually placed in a rock cleft, covered with a split burden basket, and heaped over with rocks" (Zigmond 1986, p. 404).

Historic Setting

The earliest European account of the Fremont Valley dates to the eighteenth century. A Franciscan missionary, Francisco Garcés, while exploring overland routes between the southern California missions and those in New Mexico, camped at Castle Butte in what is now California City in the Fremont Valley in the summer of 1776, as recorded in his diary. The American army officer, John C. Frémont, would explore the valley in 1844, resulting in it being named for him (BS 2008a, p. 5.4-9; Feller n.d.a; Feller n.d.b; californiacity-ca.us 2009).

With the Gold Rush attracting prospectors from all over the world to California, it is not surprising that mining was what brought the earliest Euro-American settlement to the Fremont Valley. North of the BSEP, in the El Paso Mountains, gold and silver mining began in the early 1860s at the Manzanillo Mine in the El Paso Mining District on Laurel Mountain, but the murder, in August, 1864, of the mine superintendant by bandits or Indians frightened the miners into leaving this remote and dangerous area. The depression of the early 1890s, however, brought prospectors back to the El Pasos, with the result that the peak mining period in this area was in the 1890s. One of the more productive areas in the El Pasos was the Goler Mining District. In the winter of 1893-1894 placer gold was discovered in Goler Gulch, and within two years more than $500,000 worth of gold was recovered. Charlie Koehn[3] was a local homesteader who was one of the first to profit from the Goler strike. Expecting to take advantage of miners going between Tehachapi and the Panamint Range, Koehn had already established a way station at Kane Springs, only 12 miles from Goler Gulch, when the Goler gold discovery occurred. Koehn sold supplies and hauled freight into the mountains. He added a post office to his station on September 22, 1893 (Vredenburgh, et al., 1981, pp. 184–5; Vredenburgh, n.d.).

Early trails through the Fremont Valley were located between water sources where topography favored the easiest travel. Water sources influenced where early Euro-American settlements were established. As mining in the region proved profitable in the mid-nineteenth century, roads developed connecting the mines to the sources of needed goods and services, and the roads encouraged further settlement along them. The Owens River Road tied the silver and lead mines at Cerro Gordo to Los Angeles, passing through the Fremont Valley en route. Over this freight road, in the 1870s, a French Canadian named Remi Nadeau used 14–20-mule teams pulling three heavily loaded wagons to haul supplies from Los Angles north to the mine and to return with bullion for shipment by boat from San Pedro to San Francisco. Nadeau established wagon stops at 13–20 mile intervals—a day's haul, and had two pairs of teams, one pair going south and one pair going north, plodding back and forth between the same two stations, each day hitched to a new set of wagons. Thus he had 48–52 teams each day hauling freight or bullion, with additional teams hauling feed for his animals (McManus 1987, p. 5; Nadeau 1949b, pp. 8–9). Rail transport supplanted the mule teams in 1882, but the freight road alignment is today very closely followed by SR 14 (McManus 1987, p. 5).

In 1895, Eugene Garlock chose the crossroads location of Cow Wells to set up a steam-driven, eight-stamp ore-crushing mill, hauled from Tehachapi. Garlock chose Cow Wells because of the water supply, needed for ore processing, the existing roads, and its central location among the mining districts. Named for the mill owner, the tent, frame, and adobe settlement of Garlock prospered, eventually boasting of two bars, two hotels, a stage depot, a laundry, a school, and a doctor's/dentist's office. Demand for ore processing was such that other stamp mills were soon set up nearby. The Randsburg Railway, completed in 1898, however, deprived Garlock of its primary business by hauling ore off to more efficient mills elsewhere. The town quickly declined. Most of Garlock's population had moved to Randsburg by 1900. Garlock experienced a short-lived resurgence in the 1920s in response to the salt production on Koehn Dry Lake and renewed interest in area gold mines. The Garlock post office closed forever on June 30, 1926 (Vredenburgh, et al., 1981, p. 186).

The railroads came to the region beginning in 1882. The first railroad through the Mojave Desert was built by the Southern Pacific between the towns of Mojave and

[3] "Koehn" is pronounced "Kane." Koehn Dry Lake is named for this early settler in the region.

Needles. Construction began in Mojave on February 20, 1882 and had reached Waterman (Barstow) by October 23, 1882. The line was completed to Needles on April 19, 1883 (Myrick 1992, pp. 765–766). In October, 1884, the line was purchased by the Atlantic and Pacific Railroad (A&P) and subsequently was acquired by the Atchison, Topeka, and Santa Fe Railroad (ATSF) in 1890. The ATSF, now known as the Burlington Northern Santa Fe Railroad, continues to operate the line up to the present (Myrick 1992, pp. 766, 788). In 1885 the California Southern Railroad was extended to the Mojave-Needles line through the Cajon Pass from San Bernardino. This new line, which also was soon acquired by ATSF, connected Los Angeles to the East and gave the interior region of southern California access to coastal ports (Myrick 1992).

To facilitate the construction of the first Los Angeles Aqueduct, between 1908 and 1910, the Southern Pacific Railroad Company (SP) built what came to be referred to as its "Jawbone Branch." This section ran north from Mojave to Olancha, passing just to the west of the proposed BSEP plant site (Apple and Glenny 2008, p. 24). Estimating project-required freight-hauling at 14 million tons, the engineers designing and planning the new aqueduct for the City of Los Angeles considered rail transportation the most cost-effective way to transport men and materials (LADWP n.d.). So the City approached several railroads about building a line parallel to the route of the aqueduct, but only SP responded. On April 10, 1908, SP and the City signed a contract for SP to build the standard-gauge railroad branch line that came to be known as the Jawbone, taking this name from the section of the aqueduct the rail branch was intended to serve, which traversed very rough, mountainous terrain. Cantil, just southwest of the proposed BSEP plant site, was one of the stations on the Jawbone branch. With the completion of the aqueduct, the Jawbone branch eventually was extended to Owenyo in the Owens Valley, joining the Carson and Colorado Railroad to establish through service to the East. The branch was absorbed into the SP system in 1913 (Speer 1985, p. 2), and is now part of the Union Pacific system.

The first Los Angeles Aqueduct, which captured the Owens River to provide an abundant and reliable water source for the growing City of Los Angeles is located just to the west of the project area. It was constructed between 1907 and 1913. The 1916 final report for the project provides these statistics: "Included in this work were 215 miles of road, 230 miles of pipe line, 218 miles of power transmission line, and 377 miles of telegraph and telephone line. Fifty-seven camps were established along the line of work, most of them in the mountains, and good roads made to reach them" (LADWP n.d.).

The laborers numbered 3,900 at their peak force. They blasted and drilled 142 tunnels totaling more than 43 miles in length and installed 12 miles of steel siphon. They built 34 miles of open, unlined channel, 39 miles of concrete-lined channel, and 98 miles of covered conduit which was cast in place. Some of the conduit was large enough to drive a car through (LADWP n.d.).

Concrete was the most prevalent construction material for the aqueduct. For efficiency, the project acquired resources and construction raw materials near the aqueduct and railroad routes. The City purchased 4,300 acres of land covering limestone quarries, clay deposits, and deposits of tufa (used for making concrete), and built the Monolith Mill at Cuddleback Ranch, five miles east of Tehachapi on SP's main line, where the materials for making 1,000 barrels of Portland cement a day were assembled. The City additionally imported 200,000 barrels of cement from other sources (LADWP n.d.).

The aqueduct's Jawbone Division headquarters was at Cinco, two miles southwest of Cantil on the Jawbone Branch railroad. There the Division engineer supervised 1,203 day laborers (the most workers on any of the aqueduct's divisions), who lived in six permanent camps along the aqueduct route. The camps consisted of portable wood-floored, canvas-walled-and-roofed bunkhouses and mess halls (all with furniture) and wood-frame warehouses and a store. The camps were connected to Cinco by roads, water pipelines, and electrical and telephone lines (Speer 1985, p. 3).

The rail station at Saltdale was established to service salt-mining operations at the north end of Koehn Dry Lake. The Diamond Salt Company began development activities on the lake in 1911 and 1912, but the Consolidated Salt Company was the first to begin salt production in 1914. The early salt-mining companies depended on rainfall and storm runoff to flood the dry lake and dissolve the salts in the soil, and on the sun to evaporate the brine, leaving a crust of harvestable salt. Consequently, in some dry years, no salt harvesting could be done. Later on, companies pumped ground water from wells and used ditches and flumes to flood the lake, thereby assuring reliable salt production. The Long Beach Salt Company was still producing salt in this way at Koehn Dry Lake in 1980 (Vredenburgh, et al., 1981, pp. 188–9).

Little historical information on the rural Cantil community was readily available. The rail station, established in 1908, may have been the start of Cantil, which today apparently includes the area within and around the proposed BSEP plant site and consists of approximately 35 to 40 scattered single-family residences and mobile homes on 2.5-acre to 10-acre parcels. No community facilities, such as schools, stores, or recreational facilities, are present (BS 2008a, p. 5.7-10).

The nearest developed area with a full range of community services is California City, whose northern boundary is approximately four miles south of the BSEP plant site (BS 2008a, p. 5.7-10). California City had its origins in 1958 when real estate developer and sociology professor Nat Mendelsohn purchased 80,000 acres of Mojave Desert land with the hope of master-planning California's next great city. He designed his model city around a central park with a 26-acre artificial lake. Mendelsohn's dream city, which he hoped would one day rival Los Angeles (californiacity-ca.us 2009), was established on December 10, 1965 (californiacity.com 2009). Today California City is the third largest city, in area, in California, encompassing 204 square miles (californiacity.com). The estimated population in July, 2006, was 12,659, supported by employment at Edwards Air Force Base, which is located just to the south of the city, California City Correctional Center, and U.S. Borax (californiacity-ca.us 2009).

For most of the twentieth century, the proposed BSEP plant site was undeveloped desert. The 2,273-acre Fremont Valley Ranch was established in that location in 1977 to grow alfalfa for a cattle-fattening operation on the ranch. The BSEP is now proposed to occupy some 2,012 acres of the former ranch. Alfalfa farming at the Fremont Valley Ranch was abandoned in approximately 1988 (ENSR 2007, p. I; p. 4-1), leaving no traces in the form of enhanced agricultural soils or surface water delivery systems. With only ground water available to support agriculture, it is considered an unsustainable industry in this location (BS 2008a, p. 5.7-10).

CULTURAL RESOURCES INVENTORY

A project-specific cultural resources inventory is a necessary step in staff's effort to determine whether the proposed project may cause significant impacts to historically significant (CRHR-eligible) cultural resources and would therefore, under CEQA, have an adverse effect on the environment.

The development of a cultural resources inventory entails working through a sequence of investigatory phases. Generally the research process proceeds from the known to the unknown. These phases typically involve doing background research to identify known cultural resources, conducting fieldwork to collect requisite primary data on not-yet-identified cultural resources in the vicinity of the proposed project, assessing the results of any geotechnical studies or environmental assessments completed for the proposed project site, and compiling recommendations or determinations of historical significance (see "Determining the Historical Significance of Cultural Resources," below) for any cultural resources that are identified.

This subsection describes the research methods used by the applicant and Energy Commission staff for each phase and provides the results of the research, including literature and records searches (California Historical Resources Information System (CHRIS) and local records), Native American consultation, and field investigations. Staff provides a description of each identified cultural resource, its historical significance, and the basis for its significance evaluation. Assessments of the project's impacts on historically significant cultural resources, potential impacts on previously unidentified, buried archaeological resources, and proposed mitigation measures for all significant impacts are presented in a separate subsection below.

Staff's Area of Analysis

The inventorying of cultural resources within what staff defines as the appropriate area for the analysis of a project's potential impacts is the first step in the assessment of whether the proposed project may cause a significant impact to a CRHR-eligible cultural resource and therefore have an adverse effect on the environment. The area that staff considers when identifying and assessing impacts to historical resources, called the "area of analysis" for the project, is usually defined as the area within and surrounding the project site and associated linear facility corridors. The area varies in extent depending on whether the cultural resource is an archaeological, ethnographic, or built-environment resource:

- For archaeological resources, the area of analysis is minimally defined as the proposed project site footprint, plus a buffer of 200 feet, and the proposed project linear facilities routes, plus 50 feet to either side of the routes. For this project the archaeological area of analysis includes the proposed project site footprint and its 200-foot buffer, referred to as the "project site," and the proposed ancillary linear facilities and their respective buffers, referred to collectively, including the project site, as the "project area."

- For ethnographic resources, the area of analysis is expanded to take into account traditional use areas and traditional cultural places which may be further afield than the project site or the project area. The area of analysis for ethnographic resources may include viewscapes that contribute to the historical integrity of a subject resource. Ethnographic resources are often identified in consultation with Native Americans as well as other ethnic or cultural communities, and issues that are raised by these communities may define the area of analysis. For this project the ethnographic area of analysis is the geographic area around and including the proposed project where the project has the potential to physically or visually degrade ethnographic resources.
- For built-environment resources, the area of analysis is minimally defined as one parcel deep from the project site footprint in urban areas, but in rural areas is expanded to include a half-mile buffer from the project site, and from any above-ground linear facilities, to encompass resources whose setting could be adversely affected by industrial development. For this project, the built-environment area of analysis is that minimum.
- For a historic district or a cultural landscape, Energy Commission staff defines the area of analysis based on the particulars of each siting case.

Determining the Historical Significance of Cultural Resources

CEQA requires the Energy Commission, as a lead agency, to evaluate the historical significance of cultural resources by determining whether they meet several sets of specified criteria. Under CEQA, the definition of a historically significant cultural resource is that it is eligible for listing in the CRHR, and such a cultural resource is referred to as a “historical resource, which is a “resource listed in, or determined to be eligible by the State Historical Resources Commission, for listing in the CRHR”, or “a resource listed in a local register of historical resources or identified as significant in a historical resource survey meeting the requirements of section 5024.1 (g) of the Public Resources Code,” or “any object, building, structure, site, area, place, record, or manuscript which a lead agency determines to be historically significant or significant in the architectural, engineering, scientific, economic, agricultural, educational, social, political, military, or cultural annals of California, provided the agency’s determination is supported by substantial evidence in light of the whole record” (Cal. Code Regs., tit. 14, § 15064.5(a)). The term, “historical resource,” therefore, indicates a cultural resource that is historically significant and eligible for the CRHR.

Consequently, under the CEQA Guidelines, to be historically significant, a cultural resource must meet the criteria for listing in the CRHR. These criteria are essentially the same as the eligibility criteria for the National Register of Historical Places (NRHP). In addition to being at least 50 years old, a resource must meet at least one (and may meet more than one) of the following four criteria (Pub. Resources Code, § 5024.1):

- Criterion 1, is associated with events that have made a significant contribution to the broad patterns of our history;
- Criterion 2, is associated with the lives of persons significant in our past;

- Criterion 3, embodies the distinctive characteristics of a type, period, or method of construction, or represents the work of a master, or possesses high artistic values; or
- Criterion 4, has yielded, or may be likely to yield, information important to history or prehistory.

Historical resources must also possess sufficient integrity of location, design, setting, materials, workmanship, feeling, and association to convey their historical significance (Cal. Code Regs., tit. 14, § 4852(c)).

Additionally, cultural resources listed in or formally determined eligible for the NRHP and California Registered Historical Landmarks numbered No. 770 and up are automatically listed in the CRHR and are therefore also historical resources (Pub. Resources Code, § 5024.1(d)). Even if a cultural resource is not listed or determined to be eligible for listing in the CRHR, CEQA allows a lead agency to make a determination as to whether it is a historical resource (Pub. Resources Code, § 21084.1).

Background Research

The background research for the present analysis consists of information on known cultural resources that the applicant and Energy Commission staff gathered from literature and record searches, from local government databases and local historical and archaeological societies, and information that the applicant gathered through consultation with local Native American groups. For the applicant, the purpose of the background information is to initiate the compilation of the cultural resources inventory for the project area of analysis, to identify information gaps, and to inform the design and the interpretation of the field research that will serve to complete the inventory.

Literature and Records Search

The literature and records search portion of the background research attempts to gather and interpret documentary evidence of the known cultural resources in the broader project area of analysis. The primary source for the present effort is the Southern San Joaquin Valley Archeological Information Center (SSJVAIC) of the California Historical Resources Information System (CHRIS). The archaeologists for the applicant also conducted additional archival research at a number of other regional repositories (see "Additional Archival Research" subsection, below). Energy Commission staff supplemented the primary record search with a brief review of the available archaeological literature in the region just beyond the project area of analysis (see "Literature Search on Buried Archaeological Deposits near the Project Area" subsection, below).

CHRIS Search

Methods

The archaeologists for the applicant commissioned a literature search of the BSEP project area by the staff at the SSJVIC of the CHRIS at California State University at Bakersfield. The archaeologists defined a literature search area of a one mile around the proposed project site and associated laydown and/or parking areas, and of one-quarter mile around the proposed linear facilities, including the natural gas pipeline and the two alternative transmission line routes. The CHRIS literature and records review included all recorded archaeological sites and built-environment resources, as well as all known cultural resources survey and excavation reports. Additionally, SSJVIC staff searched the following sources:

- National Register of Historic Places (NHRP);
- California Register of Historical Resources (CRHR);
- California State Historic Landmarks;
- California Points of Historical Interest;
- California Inventory of Historic Resources.

The archaeologists for the applicant authorized the staff at the CHRIS to conduct a records search for the proposed BSEP project (Apple and Glenny 2008, p. 21). The records search consisted of the areas proposed for project components and a 0.5-mile buffer zone surrounding them. Later, a supplemental records search was performed, with the buffer expanded to one mile, including a 0.5-mile buffer (0.25-mile on either side) for the natural gas pipeline route.

Results

The CHRIS records search identified 24 previous cultural resources studies within the record search area, two of which covered parts of the areas proposed for project components, CHRIS Document Nos. KE-2118 and 1108 (BS 2008c, revised Table 5.4-3). Cultural Resources Table 2 lists the 11 previous cultural resources investigations conducted within 0.25 mile of the proposed BSEP components and summarizes general information concerning them. Discussion of the more pertinent of these investigations follows Cultural Resources Table 3.

According to the records search, a total of nine cultural resources have been identified within the one-mile record search area (see Cultural Resources Table 3, below). Two of these are within the BSEP project area, CA-KER-3366H, which is the historic “Jawbone Branch” of the Southern Pacific Railroad and CA-KER-5264, which is a historic-period refuse scatter (BS 2008c, Records-Search Results Map).

CULTURAL RESOURCES TABLE 2
Previous Cultural Resources Investigations Conducted within 0.25 Miles of BSEP Project Area

CHRIS Document No.	Author and Date of Investigation	Title	Type of Investigation
KE-00029	Robert S. White 1996	*An Archaeological Assessment of the United Tire Recycling Corporation Project*	Records search and areal pedestrian survey
KE-00030	Robert S. White 1996	*An Archaeological Assessment of the Cornell Corrections California City Prison Site*	Records search and areal pedestrian survey
KE-00248	Michael E. Perry 1990	*Cultural Resource Survey Report for Flightline Security Fence*	Records search and areal pedestrian survey
KE-00649	James McManus 1987	*Archaeological Survey Report for 9-KER-14*	Records search and linear pedestrian survey
KE-01108	Robert A. Schiffman 1985	*Archaeological Investigation of Solar World's Proposed Wind Farm Near Cantil, Kern County, California*	Records search and areal pedestrian survey
KE-01967	Michael V. Speer 1985	*Historical Resource Evaluation Report for a Widening Project on 9-KER-14, Near Cinco, Kern County*	Historical research and site visit
KE-01968	Martha Proctor 1987	*Historic Property Survey Report, Jawbone Canyon Expressway Project*	Records search Historical research Native American consultation Pedestrian survey Windshield survey Site visits
KE-01969	Denise O'Connor 1987	*Historical Architectural Survey Report for a Proposed Highway Project on Route 14 in Kern County, California*	Map and aerial review Site visits
KE-02118	Brian F. Smith and Associates 1997	*An Archaeological Survey of the Fremont Valley Pipeline Project, Mojave, California*	Records search and linear pedestrian survey
KE-02135	James McManus 1985	*Negative Declaration [SR 14 widening]*	Records search and linear pedestrian survey
KE-03276	Stacy Jordan and Michael Wise 2006	*Archaeological Survey Report for the Southern California Edison Company, LADWP Rule 15 Line Extension, Private Inholding, Kern County, California*	Records search and areal pedestrian survey

CULTURAL RESOURCES TABLE 3
Previously Recorded Cultural Resources Located within 1.0 Miles of the BSEP Project Area

CHRIS Primary No.	CHRIS Trinomial No.	Resource Age	Resource Type
P-15-002142	CA-KER-2142H	Prehistoric and historic	Large prehistoric site, with undisturbed midden, flakes, projectile points, bifaces, and milling stones, dating from 500 BC to 500 AD; historic-period refuse scatter associated with two hearth features
*P-15-003366	CA-KER-3366H	Historic (1908–1910)	Historic railroad
P-15-003549	CA-KER-3549H	Historic (1908)	Los Angeles Aqueduct
*P-15-006415	CA-KER-5264H	Historic	Historic debris scatter
P-15-008781	CA-KER-5573H	Historic (1908)	Los Angeles Aqueduct construction camp
P-15-010089	CA-KER-5945/H	Historic (Early 1900s)	Historic period refuse and adit
P-15-012429	---	Prehistoric	Lithic scatter
P-15-012666	CA-KER-7125	Prehistoric	Rock shelter
P-15-012737	CA-KER-7194	Prehistoric	Lithic scatter

*Previously recorded site inside project area (Apple and Glenny 2008, p. 24–25)

Previous Cultural Resources Investigations

Methods

Methods employed in these studies include records searches, historical research, Native American consultation, pedestrian archaeological survey, and built-environment windshield survey and site visits.

Results

The Brian F. Smith 1997 archaeological survey (KE-2118) of the Fremont Valley Pipeline is the only previous cultural resources survey within the proposed BSEP plant site, in sections 4, 7, 8, and 9. The survey covered 100 feet to either side of the 3.5-mile-long water pipeline route, which proposed to connect four wells on the Fremont Valley Ranch to the Los Angeles Aqueduct. One historic-period archaeological site within the proposed BSEP plant site—a historic-period trash scatter—was identified and recorded as CA-KER-5264H (Smith 1997).

The Robert A. Schiffman 1985 archaeological survey (KE-1108) of a proposed wind farm covered 160 acres in the northwest corner of section 10, sharing boundaries with the BSEP plant site on its west and north sides. No cultural resources were identified (Schiffman 1985).

In the mid-to-late 1980s, Caltrans cultural resources specialists completed five studies (McManus 1985, McManus 1987, O’Connor 1987, Proctor 1987, Speer 1985) of a proposed widening of a 10-mile-long stretch of SR-14 between Mojave and Cantil. Two prehistoric archaeological sites and one historical archaeological site were identified. The historical archaeological site was the remains of Cinco, the 1908-1912 headquarters of the first Los Angeles Aqueduct's Jawbone division. The site was recommended as not eligible for the NRHP due to a loss of integrity. One of the prehistoric archaeological sites, CA-KER-2090, was interpreted as a temporary food-processing camp lacking dateable artifacts and subsurface deposits. This site is located outside of the one-mile records search area. The other prehistoric archaeological site, CA-KER-2142H, is a large site, with undisturbed midden, flakes, projectile points, bifaces, and milling stones, evidencing a range of activities, including plant processing, hunting, and lithic procurement and reduction. A date range of 500 B.C. to A.D. 500 was suggested by the recorder based on the Rose Spring projectile points. A historic-period component is also present at this site in the form of barrel hoops, glass fragments, and solder-top cans associated with two large rock hearths (O'Connor 1987, p. 3; McManus 1987, p. 6). Although none of the information available for this site includes an eligibility recommendation or an integrity assessment, Energy Commission staff considers this site probably CRHR-eligible under Criterion 4. This site is located within the one-mile records search area.

Additional Archival Research

The archaeologists for the applicant conducted additional archival research on the history of the BSEP project area of analysis at a number of repositories.

Methods

The research included a review of historic maps, aerial photographs, and information on the history of the region, seeking information on the location and age of potential historic-period resources on or near the project areas. Records on the age of buildings were checked at the Kern County Assessor's and Recorder's Office. Historic maps were sought at Stiern Library at California State University, Bakersfield; the Kern County Library; University of California, Riverside, Library; University of California, Los Angeles, Library; the Los Angeles Public Library; the County of Los Angeles Library; and the San Diego State University Library. On-line historic map databases, including the California Historic Topographical Map Collection, at California State University, Chico, and the Historical Map Archive at the University of Alabama, were accessed. Historic aerial photographs were sought at the Kern County Department of Planning, at the U. S. Department of Agriculture Aerial Photography Field Office, and in the U. S. Geological Survey (USGS) EarthExplorer Aerial photography database (Hirsch 2008, p. 17).

Results

Results from the consultant's archival research were primarily data for the historical background subsection of the cultural resources section of the AFC and historical maps showing potential historic-period resources that the field surveys would ground-truth (Hirsch 2008, p. 17).

Literature Search on Buried Archaeological Deposits near the Project Area

A brief literature search by Energy Commission staff found that recent investigations near the project site may indicate a broad, local level of sensitivity for buried archaeological deposits. The results of investigations by Sutton (1991) at archaeological site CA-KER-2211 on the Honda Test Track project, immediately east of the Beacon project site, are similar to those obtained by the applicant on the project site (see "Evaluation Phase (Phase II) Investigation of Prehistoric and Historical Archaeological Sites" subsection, below). The 1991 study found eight hearths, four of which were well-defined, a house floor, seven other archaeological features, and a cache of large obsidian flakes. The four well-defined hearths ranged in depth from 1 to 2 feet below the ground surface and from 150 to 940 years of age. The house floor was approximately 2 feet deep and 940 to 1,300 years of age. The apparent context for the features was a zone of man-made sediments, or midden, beneath a disturbed plow zone and above a layer or stratum of sterile yellow sand. In another study conducted west of the project site at CA-KER-3939 (Gardner, McGill, and Sutton 2002), three hearth features, buried between 4 and 15 feet below the present ground surface, were dated by radiocarbon assay to be between approximately 5,600 and 7,000 years old.

Native American Consultation

To obtain information on known cultural resources and to learn of any concerns Native Americans may have about the BSEP, the archaeologists for the applicant undertook to consult with Native American groups that may have an interest in the project area.

Methods

The applicant contacted the Native American Heritage Commission (NAHC) by letter in October, 2007, to request information about traditional cultural properties (for example, cemeteries and sacred places) in and around the project area and to request a list of Native Americans who have heritage ties to Kern County and want to be informed about new development projects there (Apple and Glenny 2008, p. 26). The NAHC responded on November 8, 2007 (BS 2008c, att. 3), with the information that their database had yielded no known Native American cultural resources on or near the proposed BSEP site, and a list of the names and contact information for seven Native Americans individuals or groups interested in development projects in Kern County (see Cultural Resources Table 4). The applicant sent a letter to each of the seven on November 20, 2007, asking for their input and asking about any concerns they may have about the project.

CULTURAL RESOURCES TABLE 4
Native American Contacts

Native American Group	Location of Group Contact
Tule River Indian Tribe	Porterville, Tulare County
Kawaiisu	Kernville and Weldon, Kern County
Tubatulabel	Kernville and Weldon, Kern County
Koso	Kernville and Weldon, Kern County
Yokuts	Kernville and Weldon, Kern County
Yowlumne	Covina, Los Angeles County
Kitanemuk	Covina, Los Angeles County
Paiute	Bakersfield, Kern County
Tejon Indian Tribe	Wasco, Kern County

Results

No responses had been received by the time the cultural resources technical report was published in March, 2008 (Apple and Glenny 2008, p. 26). On July 1, 2008, however, telephone calls were placed to all of the representatives. Voicemail messages were left with five of the seven, but the archaeologists for the applicant were able to speak with the remaining two representatives, John Valenzuela, of the San Fernando Band of Mission Indians, and Robert Wermuth, affiliated with the Tubatulabel, Kawaiisu, Koso, and Yokuts groups (DB 2008d, att. DR-26; Apple and Glenny 2008, p. 27). The consultant informed Mr. Valenzuela about the sites discovered during the survey and those sites proposed for testing. Mr. Valenzuela mentioned that the 7-Feathers Corporation would be willing to provide monitors during the testing phase of the project. He also indicated that he wanted to obtain as much information as possible about the project and sites before any of the project work began. He also stated that there were important traditional sites around the project area, but requested another map in order to indicate where these sites were located. On July 2, 2008, the applicant sent another map to Mr. Valenzuela. On July 8, 2008, the applicant left a voice message inquiring about the 7-Feathers Corporation providing monitors for the testing phase of the project (DB 2008d, att. DR-26).

On July 1, 2008, the archaeologists for the applicant informed Ron Wermuth about the sites discovered during the survey and those sites proposed for testing. Mr. Wermuth mentioned that he would be interested in volunteering for monitoring during the testing phase of the project. He also mentioned that traditional use areas, including rock art sites, may be within the area, but also requested another map in order to indicate where these sites were located. An email with a map was sent to him on that same day.

Neither Mr. Valenzuela nor Mr. Wermuth has responded further, nor have any of the other Native Americans contacted. Therefore, at this time Native Americans have identified no ethnographic sites or additional known prehistoric archaeological sites.

Consultation with Others

On November 29, 2007, the archaeologists for the applicant initiated contact with Kern County, and with a number of local historical societies and museums to notify them of the proposed project, and to request any information that the organizations may have on this area. To date, only one response has been received (Apple and Glenny 2008, p. 27).

Inquiry to Kern County

In its County Land Ordinance 18.05, in its Building Regulations, and in its General Plan, Kern County recognizes important historical resources listed as State Landmarks and in the CRHR and NRHP, but the County does not maintain a separate list of local historical resources. Thus no additional information on known cultural resources was obtained from this source (BS 2008c).

Inquiries to Local Historical Societies and Museums

Methods

In November, 2007, the applicant sent letters inquiring about locally recognized historical resources to the following organizations:

- Kern County Historical Society
- East Kern Historical Society
- Historical Society of the Upper Mojave Desert
- Kern Antelope Historical Society
- Boron Twenty Mule Team Museum
- Kern Valley Museum
- Maturango Museum of the Indian Wells Valley

Results

John Di Pol, of the Historical Society of the Upper Mojave Desert, provided pertinent information on December 7, 2007. Mr. Di Pol called attention to the nineteenth-century mining-associated roads that traversed the project area, to the Los Angeles Aqueduct construction camp called "Cinco," to the "R.R. siding" of Cantil as the junction of the aqueduct's Red Rock spur railroad and the Jawbone Branch, and to Desert Springs as an important waterhole for the stage and freight lines of the 1860s (Apple and Glenny 2008, att. 3).

Field Inventory Investigations

The archaeologists for the applicant are employing two phases of fieldwork to inventory the cultural resources in the project area of analysis, a geoarchaeology study and an intensive pedestrian survey (Table 5). The results, to date, have been the identification of 72 new cultural resources in the project area of analysis, not including the discovery of 59 isolate resources, the re-recordation of one previously known cultural resource, and the observation of the loss of another previously known cultural resource (Table 6). The present cultural resources inventory for the project area of analysis includes 56 archaeological resources, no ethnographic resources, and 16 built-environment resources. The outstanding results of the geoarchaeology study (see "Geoarchaeology Study" subsection, below) may add to the cultural resources inventory.

CULTURAL RESOURCES TABLE 5
Cultural Resources Inventory Investigations for the Present Analysis

Investigation Type	Results	Report Reference
Geoarchaeology Study	Pending	Pending
Intensive Pedestrian Cultural Resources Survey	Re-recordation of 3 known cultural resources, identification of 70 new cultural resources, and identification of 59 isolate cultural resources	Apple and Glenny 2008

CULTURAL RESOURCES TABLE 6
Present Cumulative Cultural Resources Inventory for the Project Area of Analysis

Cultural Resource Type and Designation (Year of Initial Recordation)	Description	Project Area Location	Preliminary California Register of Historical Resources (CRHR) Eligibility	Siting Case Report Reference
Archaeological Resources				
Prehistoric Archaeological Resources				
Site 2 (2007)	Composed of 6 cryptocrystalline silicate[4] (CCS) flakes and 1 core	Transmission line	Not eligible	Apple and Glenny 2008
Site 8 (2007)	Consists of two fire-affected rock[5] (FAR) concentrations, composed of 150 subangular granitic rocks	Plant site	Potentially eligible	Apple and Glenny 2008
Site 9 (2007)	A small FAR scatter; possibly represents remnants of a hearth	Plant site	Potentially eligible	Apple and Glenny 2008
Site 10 (2007)	Composed of 50 CCS flakes, a core, a mano fragment, two bifaces, and a scraper. Likely represents a temporary camp	Plant site	Potentially eligible	Apple and Glenny 2008
Site 11 (2007)	Consists of 25 pieces of subangular granitic FAR, representing a disturbed hearth	Plant site	Potentially eligible	Apple and Glenny 2008
Site 12 (2007)	Consists of a FAR scatter composed of 150 pieces of subangular granitic rock, and a mano fragment	Plant site	Potentially eligible	Apple and Glenny 2008
Site 13 (2007)	A small FAR scatter composed of 25 pieces of granitic rock	Plant site	Potentially eligible	Apple and Glenny 2008

[4] Cryptocrystalline silicates are rocks such as flint, chert, chalcedony, or jasper that contain a high percentage of silica (SiO^2), the primary compound that composes quartz.

[5] Fire-affected rock is rock that has been thermally altered by exposure to fire. Thermal alteration of rock may manifest as orange to red patches of oxidation and sporadic black traces of charcoal on the exterior faces of rocks, and angular rock edges that may result from heat-induced cracking.

Cultural Resource Type and Designation (Year of Initial Recordation)	Description	Project Area Location	Preliminary California Register of Historical Resources (CRHR) Eligibility	Siting Case Report Reference
Site 14 (2007)	Consists of at least 4 FAR clusters, representing hearths; also includes a metate fragment, a mano fragment, and 4 pieces of debitage	Plant site	Potentially eligible	Apple and Glenny 2008
Site 17 (2007)	Consists of 2 flakes, 1 bifacial tool, and 1 utilized flake	Plant site	Not eligible	Apple and Glenny 2008
Site 18 (2007)	Composed of 1 core chopper, 1 core fragment, and 4 CCS flakes	Plant site	Not eligible	Apple and Glenny 2008
Site 19 (2007)	Lithic scatter consists of 6 CCS flakes	Plant site	Not eligible	Apple and Glenny 2008
Site 20 (2007)	Lithic scatter consists of 2 CCS flakes and 1 bifacial tool	Transmission line	Not eligible	Apple and Glenny 2008
Site 21 (2007)	Consists of 1 scraper, 2 core fragments, and 1 flake	Transmission line	Not eligible	Apple and Glenny 2008
Site 22 (2007)	Consists of 1 biface fragment, 1 utilized flake, and 2 pieces of debitage	Transmission line	Not eligible	Apple and Glenny 2008
Site 23 (2007)	Consists of 3 cores and 6 flakes, all composed of CCS	Transmission line	Not eligible	Apple and Glenny 2008
Site 24 (2007)	Consists of 2 CCS cores and 4 CCS flakes	Transmission line	Not eligible	Apple and Glenny 2008
Site 26 (2007)	Consists of 1 scraper, 1 core, and 3 flakes, all composed of CCS	Transmission line	Not eligible	Apple and Glenny 2008
Site 27 (2007)	Consists of 1 core, 2 CCS flakes, and 1 metate fragment	Transmission line	Not eligible	Apple and Glenny 2008
Site 29 (2007)	Consists of 1 core and 2 CCS flakes	Transmission line	Not eligible	Apple and Glenny 2008
Site 30 (2007)	Consists of 1 CCS core and pieces of CCS debitage	Transmission line	Not eligible	Apple and Glenny 2008
Site 39 (2007)	Consists of 6 flakes and 1 core	Transmission line	Not eligible	Apple and Glenny 2008

Cultural Resource Type and Designation (Year of Initial Recordation)	Description	Project Area Location	Preliminary California Register of Historical Resources (CRHR) Eligibility	Siting Case Report Reference
Site 40 (2007) [CA-KER-2142/H (1986)]	Consists of several partially buried hearths, 70+ CCS flakes, 1 obsidian core, 1 mano fragment, and 1 metate fragment; Site 59 (a prehistoric trail) extends through this site	Transmission line	Potentially eligible	Apple and Glenny 2008
Site 41 (2007)	Consists of 2 CCS cores and 2 CCS flakes	Transmission line	Not eligible	Apple and Glenny 2008
Site 42 (2007)	Consists of 3 CCS flakes	Transmission line	Not eligible	Apple and Glenny 2008
Site 43 (2007)	Consists of 10 CCS flakes and 1 CCS core	Transmission line	Not eligible	Apple and Glenny 2008
Site 44 (2007)	Consists of 4 CCS flakes	Transmission line	Not eligible	Apple and Glenny 2008
Site 46 (2007)	Consists of 4 CCS cores and 8 CCS flakes	Transmission line	Not eligible	Apple and Glenny 2008
Site 47 (2007)	Consists of 5 flakes, 1 core, and 1 tool	Transmission line	Not eligible	Apple and Glenny 2008
Site 48 (2007)	Consists of 2 cores, 6 pieces of debitage, and 1 scraper	Transmission line	Not eligible	Apple and Glenny 2008
Site 50 (2007)	Consists of 8 CCS flakes, 1 obsidian flake, 2 cores, and 1 scraper	Transmission line	Potentially eligible	Apple and Glenny 2008
Site 51 (2007)	Consists of 18 CCS flakes	Transmission line	Potentially eligible	Apple and Glenny 2008
Site 52 (2007)	Consists of 4 pieces of debitage and 1 utilized flake	Transmission line	Not eligible	Apple and Glenny 2008
Site 54 (2007)	Consists of 10 flakes, 1 modified flake, and 1 core, all composed of CCS	Transmission line	Potentially eligible	Apple and Glenny 2008
Site 55 (2007)	Consists of 4 pieces of CCS debitage	Transmission line	Not eligible	Apple and Glenny 2008

Cultural Resource Type and Designation (Year of Initial Recordation)	Description	Project Area Location	Preliminary California Register of Historical Resources (CRHR) Eligibility	Siting Case Report Reference
Site 56 (2007)	Consists of 3 CCS cores and 2 CCS flakes	Transmission line	Not eligible	Apple and Glenny 2008
Site 57 (2007)	Consists of 4 CCS flakes	Transmission line	Not eligible	Apple and Glenny 2008
Site 58 (2007)	Consists of 2 CCS flakes and 1 CCS core	Transmission line	Not eligible	
Site 59 (2007)	Trail measures 30 to 35 cm wide, and extends to the north ~2 km; it also extends through Site 40 and would cross through Transmission line Option 1	Transmission line	Potentially eligible	Apple and Glenny 2008
Historical Archaeological Resources				
Site BSPL-H-01 (2007)[6]	Consists of cans, glass, and some indeterminate metal fragments; includes white ceramics, window glass, tobacco cans, green aqua glass, and some hole-in-top cans	Natural gas pipeline	Not eligible	Apple and Glenny 2008
Site BSPL-H-02 (2007)	Consists of concrete foundation with associated cistern; refuse scatter consists of purple glass, hole-in-top cans, and barbed wire	Natural gas pipeline	Potentially eligible	Apple and Glenny 2008
CA-KER-5264H[7] (1997)	Scatter containing glass fragments, ceramics, round nails, a glove, and indeterminate metal	Plant site	Not relocated	

[6] [Temporary Field Designation No.]
[7] CHRIS Trinomial No.

Cultural Resource Type and Designation (Year of Initial Recordation)	Description	Project Area Location	Preliminary California Register of Historical Resources (CRHR) Eligibility	Siting Case Report Reference
Site 16 (2007)	Historic-period and modern refuse; historic-period refuse includes aqua glass, green and brown glass, and ceramics; modern refuse includes indeterminate metal fragments, auto parts, and a can opener	Plant site	Not eligible	Apple and Glenny 2008
Site 31 (2007)	Consists of food cans, glass fragments, one assay crucible, tobacco cans, ceramics, and some modern car parts; also present are indeterminate metal debris and ~250 cans	Transmission line	Potentially eligible	Apple and Glenny 2008
Site 32 (2007)	Dense concentration includes mattress springs, galvanized metal, green and brown glass fragments and some indeterminate metal	Transmission line	Not eligible	Apple and Glenny 2008
Site 33 (2007)	Consists of ~25 cans, fragments of a 50-gallon drum, and corrugated metal sheets	Transmission line	Not eligible	Apple and Glenny 2008
Site 34 (2007)	Consists of cans, glass, ceramic fragments, and a purple cork top bottle fragment	Transmission line	Not eligible	Apple and Glenny 2008
Site 35 (2007)	Consists of glass, ceramics, and non-diagnostic metal; also includes some modern debris	Transmission line	Not eligible	Apple and Glenny 2008

Cultural Resource Type and Designation (Year of Initial Recordation)	Description	Project Area Location	Preliminary California Register of Historical Resources (CRHR) Eligibility	Siting Case Report Reference
Site 36 (2007)	Consists of over 200 historic cans, clear and brown glass fragments, and a tea cup fragment; some modern debris also present	Transmission line	Potentially eligible	Apple and Glenny 2008
Site 37 (2007)	Consists of melted glass, hold-in-top cans, a framework of a cot, milled lumber, and non-diagnostic metal	Transmission line	Not eligible	Apple and Glenny 2008
Site 45 (2007)	Consists of 2 loci: Locus 1 is composed of milled wood and porcelain; Locus 2 is composed of mattress springs, tin cans, and glass fragments	Transmission line	Not eligible	Apple and Glenny 2008
Site 53 (2007)	Consists of 25 can (soldered top), a lantern base, and a gallon oil can	Transmission line	Not eligible	Apple and Glenny 2008
Multiple-Component Archaeological Resources				
Site 1 (2007)[8]	Lithic scatter composed of 6 cryptocrystalline silicate (CCS) flakes; historic-period refuse concentration composed of a kerosene can, aqua glass sherds from a Mason jar, four soldered top cans, a wire handle, remnants of a 55-gallon drum, and several modern cans	Transmission line	Not eligible	Apple and Glenny 2008

[8] Temporary Field Designation No.

Cultural Resource Type and Designation (Year of Initial Recordation)	Description	Project Area Location	Preliminary California Register of Historical Resources (CRHR) Eligibility	Siting Case Report Reference
Site 3 (2007)	Two historic-period refuse scatters composed of a metal lock, ceramic sherd with polychrome flower pattern on edge, aqua glass bottle base, a Prince Albert tobacco tin, an embossed aqua glass fragment, a square bolt, a brown cork top bottle neck, a curved tobacco can, and earthenware ceramic sherds	Transmission line	Potentially eligible	Apple and Glenny 2008
Site 6 (2007)	Lithic scatter consists of 8 CCS flakes, 5 CCS cores, a point fragment, and a utilized flake; historic-period refuse scatter consists of two ceramic scatter and several aqua colored glass fragments	Transmission line	Potentially eligible	Apple and Glenny 2008
Site 25 (2007)	Consists of a 1 scraper, 1 core fragment, 4 pieces of debitage, and 1 glass bottle-neck	Transmission line	Not eligible	Apple and Glenny 2008
Site 28 (2007)	Lithic scatter consists of 1 CCS core and 1 CCS flake; historic-period refuse concentration composed of wood, pull-top cans, 1 polychrome flower print plate, a toothpaste can, clear glass fragments, and indeterminate metal fragments	Transmission line	Not eligible	Apple and Glenny 2008

Cultural Resource Type and Designation (Year of Initial Recordation)	Description	Project Area Location	Preliminary California Register of Historical Resources (CRHR) Eligibility	Siting Case Report Reference
Site 38 (2007)	Consists of purple glass fragments, 2 flakes, and 2 cores	Transmission line	Not eligible	Apple and Glenny 2008
Site 49 (2007)	Lithic scatter consists of 1 CCS core and 10 CCS flakes; historic-period refuse consists of 1 tobacco tin, fragments of purple glass, and 1 hole-in-top can	Transmission line	Not eligible	Apple and Glenny 2008
Ethnographic Resources	None presently known			
Built-Environment Resources				
7696 Neuralia Road, California City (2007)	Rancho Cantil	Plant site buffer zone	Potentially eligible	BS 2008a
21257 79th Street, California City (2007)	Built in 1964	Natural gas pipeline	Not eligible	BS 2008a
21225 Neuralia Road, California City (2007)	Built in 1964	Natural gas pipeline	Not eligible	BS 2008a
21209 Neuralia Road, California City (2007)	Built in 1964	Natural gas pipeline	Not eligible	BS 2008a
21125 Neuralia Road, California City (2007)	Built in 1964	Natural gas pipeline	Not eligible	BS 2008a
21101 Neuralia Road, California City (2007)	Built in 1964	Natural gas pipeline	Not eligible	BS 2008a
21049 Neuralia Road, California City (2007)	Built in 1964	Natural gas pipeline	Not eligible	BS 2008a
21041 Neuralia Road, California City (2007)	Built in 1963	Natural gas pipeline	Not eligible	BS 2008a
21033 Neuralia Road, California City (2007)	Built in 1963	Natural gas pipeline	Not eligible	BS 2008a
21025 Neuralia Road, California City (2007)	Built in 1963	Natural gas pipeline	Not eligible	BS 2008a

Cultural Resource Type and Designation (Year of Initial Recordation)	Description	Project Area Location	Preliminary California Register of Historical Resources (CRHR) Eligibility	Siting Case Report Reference
21017 Neuralia Road, California City (2007)	Built in 1963	Natural gas pipeline	Not eligible	BS 2008a
21009 Neuralia Road, California City (2007)	Built in 1963	Natural gas pipeline	Not eligible	BS 2008a
21001 Neuralia Road, California City (2007)	Built in 1963	Natural gas pipeline	Not eligible	BS 2008a
21000 79th Street, California City (2007)	Built in 1963	Natural gas pipeline	Not eligible	BS 2008a
21001 79th Street, California City (2007)	Built in 1963	Natural gas pipeline	Not eligible	BS 2008a
CA-KER-3366H (1992)	A section of the Southern Pacific Railroad, "Jawbone Branch"	Transmission line	Potentially eligible	BS 2008a

This subsection discusses both field inventory phases and provides a raw summary of the resultant cultural resources inventory for the project area of analysis, to date. Thorough descriptions of each cultural resource in the inventory, evaluations of the eligibility of each resource for listing in the CRHR, assessments of project impacts on each determined historical resource, consideration of potential impacts on archaeological resources that may lie buried in the project site, and proposed mitigation measures for significant impacts may be found in the "California Register of Historical Resources Evaluations" and "Assessment of Impacts and Discussion of Mitigation" subsections, below.

Geoarchaeology[9] Study

Staff made a request to the applicant in June, 2008 (Data Request No. 34) to provide information that would facilitate the assessment of the potential for the project to encounter buried archaeological deposits during its construction, operation, and maintenance. The request sought a discussion of the historical development of the landforms that compose the project site, the basis for which was to be an appropriate combination of extant literature and primary field research (CEC 2008bb). The August, 2008 response from the applicant (BS 2008g) was a letter report that summarizes the geomorphology of the project area on the basis of extant geologic and soil science data

[9] Geoarchaeology is a subdiscipline of archaeology that uses the techniques and approaches of earth sciences, such as geology, geomorphology, sedimentology, pedology, and stratigraphy, to identify, investigate, and interpret the history of the human use of present and former landscapes.

for the region and on the basis of the applicant's consultant's previous geotechnical investigations of the project site. The letter report concludes that recent (1,000 to 8,000 years before present) alluvial fan deposits that cover approximately 80 percent of the project site, and the alluvial stream deposits that cover the floors of the drainages that have incised channels into those alluvial fan deposits and into older (15,000 to 19,000 years before present) alluvial fan deposits above and to the west of the former deposits, have the potential for buried archaeological deposits that would date from the present to 12,000 years ago. The letter report also states that the recent (present to 8,700 years before present) deposits of lake sediments that cover approximately 20 percent of the project site along its northern boundary are an unlikely place to find archaeological deposits.

The results of an October, 2008 study to evaluate the historical significance of eight archaeological sites in the project area (Apple, Cleland, and Glenny 2008) documents the presence of significant intact buried prehistoric archaeological deposits beneath the surface of the project site (see "Evaluation Phase (Phase II) Investigation of Prehistoric and Historical Archaeological Sites" subsection, below). The investigation of, among others, five archaeological sites that are surface concentrations of fire-affected rock revealed the presence of six, intact buried fire features or hearths that range in age from approximately 190 to 560 years old. The tops of the hearths were found at depths from approximately 13 to 70 centimeters below the present surface of the project site, and were apparently not evident from that surface. It is of note that four of the five subject sites were found in the lake sediment deposits in the northern portion of the project site, where the August, 2008 letter report states such archaeological deposits are unlikely to be present.

The results documented in the August, 2008 letter report, the October, 2008 evaluation study, and articles on the archaeology of the project vicinity (see "Literature Search on Buried Archaeological Deposits Near the Project Site" subsection, above), demonstrate that buried archaeological deposits are present on the project site, in both of the major geologic contexts, and indicate that these deposits may be present to the maximum depth of ground disturbance anticipated for the construction of the proposed project. Still, this evidence does not provide staff a sufficient basis for the substantive analysis and mitigation of the impacts that the construction of the proposed project may have on cultural resources because staff lacks information on the extent to which buried cultural resources are present on the proposed BSEP plant site.

To develop a fact-based approximation of the scale of the presence of buried archaeological resources on the proposed plant site and, consequently, of the scope of the impacts that the project would have on them to facilitate the development of effective mitigation measures, staff presented the applicant with Supplement to Data Request 34 on December 16, 2008. This supplemental data request asks for information on the potential distribution patterns of buried archaeological deposits across and beneath the project site, on the geologic deposits with which the buried archaeological deposits are associated, and the approximate ages and types of archaeological sites that those deposits represent. More specifically, the data request supplement asks that the applicant augment the results of the August, 2008 letter report with a geoarchaeology study that would map the landforms and major landform features of the project site, conduct primary field research to document the stratigraphy of the project site, analyze the records from the field effort and the material culture that may be found, and prepare a conclusory archaeological assessment of the project site.

The applicant has agreed to provide the information for which Supplement to Data Request 34 asks. The applicant is presently in the process of gathering that information and foresees being able to provide preliminary responses prior to the publication of the Final Staff Assessment. This additional information is critical to preparing a substantive, factual analysis of the proposed project's potential to impact cultural resources, and to informing the development of conditions of certification that may more genuinely reduce such impacts to less than significant.

Intensive Pedestrian Cultural Resources Survey

The archaeologists for the applicant undertook an intensive pedestrian cultural resources survey of the proposed project area to comply with the Energy Commission's siting regulations. The purpose of the survey was to provide information on the location and the character of the cultural resources that may lie on the surface of the project area. The resulting information informs the present analysis of the project's potential effects on historical resources.

Methods

The cultural resources survey of the BSEP project area was conducted from October through December, 2007 (Apple and Glenny 2008, p. 29). The survey included coverage of the entire proposed plant site, plus a 200-foot buffer zone extending beyond the plant site boundary. The pedestrian survey for the natural gas pipeline and the two alternate transmission line routes covered the proposed route rights-of-way, plus 50 feet to either side of the centerline of the routes. Additionally, built-environment resources within one-half mile of the proposed project site, of both transmission line route alternatives, and of the natural gas pipeline route were inventoried (Hirsch 2008, pp. 20, 30).

The standard transect interval for the pedestrian survey was 20 meters in width (Apple and Glenny 2008, p. 30). Once survey personnel entered a portion of California City along the natural gas pipeline route, however, transect spacing was slightly altered due to the presence of a four-lane road with a center divide. A hand-held Trimble GeoXT submeter GPS unit was used for recording site location data, and a sketch map was also produced. Photographs were taken of selected artifacts.

The applicant also sought to identify built-environment resources that could be impacted by the proposed BSEP. The applicant reviewed historic maps for structures 45 years of age or older and, in November and December of 2007, conducted an intensive survey of the main plant site, or project site, the areas proposed for the two transmission line alternatives, and a 0.5-mile buffer zone around these components. For the natural gas pipeline route, which traversed both urban and rural areas, parcels adjacent to the pipeline route in the urban areas and within a 0.5-mile buffer zone to either side of the route in the rural areas were surveyed, documenting and photographing all of the structures found (Hirsch 2008, p. 20).

Results

As a result of the intensive pedestrian cultural resources survey, 57 new archaeological sites and 59 archaeological isolates were found (Apple and Glenny 2008, pp. 31-32, 54). The new archaeological sites consisted of 38 prehistoric, 12 historical, and 7 multiple-component archaeological sites. The archaeological isolates consisted of 55 prehistoric, 3 historical, and 1 multiple-component resources. The prehistoric archaeological site types include lithic scatters of stone tools and stone tool manufacturing and maintenance debris, fire-affected rock scatters, potential campsites, and a trail. The historical archaeological site types consist principally of debris and refuse scatters. The multiple-component sites include a combination of lithic scatters and historic refuse scatters. The isolate types include prehistoric lithics and historic refuse, with one isolate representing both lithics and historic refuse. Cultural Resources Table 6 summarizes the previously known and newly identified archaeological sites.

The applicant sought to identify standing structures that would be 45 years of age or older in 2010, ultimately recognizing 15 standing structures and one linear built-environment resource within the main plant site, or project site, along the transmission line alternatives, and along the natural gas pipeline (Hirsch 2008, p. 20). Of the 15 standing structures, only one structure was initially considered potentially significant and documented. This house was known historically as "Rancho Cantil" (Hirsch 2008, p. 20). The other 14 standing structures that were documented were located within one-half mile of the natural gas pipeline route. The linear built-environment resource is the Jawbone Branch of the Southern Pacific Railroad, a segment of which forms the western boundary of the BSEP project site. Cultural Resources Table 6 summarizes the previously known and newly identified built-environment resources.

Summary of Field Inventory Results

The present cultural resources inventory for the project area includes 57 archaeological sites, 15 standing structures, and one historic railroad (see Cultural Resources Table 6, above). Background research and Native American consultation did not reveal the presence of ethnographic resources in the project area of analysis. The archaeological resources inventory is tentative pending the results of the geoarchaeology study (see "Geoarchaeology Study" subsection, above).

California Register of Historical Resources Evaluations

Evaluation Phase (Phase II) Investigation of Prehistoric and Historical Archaeological Sites

The applicant originally made a determination that the proposed project had the potential to impact 18 of the 57 archaeological sites found as a result of the intensive pedestrian cultural resources survey (Apple, Cleland, and Glenny 2008:v) (see also "Intensive Pedestrian Cultural Resources Survey" subsection, above). The applicant, in consultation with Energy Commission staff (CEC 2008a), developed a program to evaluate the historical significance of each of the 18 archaeological sites. The program provides for the evaluation of a subset of the subject sites on the basis of surface observations where the applicant is able to use such observations to support defensible evaluation arguments. The applicant made recommendations on the historical significance of 6 of the 18 archaeological sites in this manner. Subsequent to the applicant and Energy Commission staff consultation on the evaluation program, but prior to the implementation of the program, the applicant made the determination that the proposed project would avoid four additional archaeological sites (Apple, Cleland, and Glenny 2008:v). The balance of eight archaeological sites were each subject to additional surface documentation, one was subject to additional archival research, and six were subject to limited excavation to gather the minimum amount of information necessary to conclude historical significance recommendations (Apple, Cleland, and Glenny 2008). Subsequent to the implementation of the evaluation program, the applicant made the further determination that the proposed project would avoid 1 of the 8 archaeological sites that had been subject to additional fieldwork, leaving the present total number of archaeological sites that the proposed project may impact at 13. The results of the evaluation program identify which of the above 13 archaeological sites in the project area are historical resources under CEQA and require further consideration in the present analysis.

Methods

The archaeologists for the applicant conducted the field phase of the evaluation program from July 30 through August 14, 2008. Each of the eight archaeological sites that were part of the field investigation (Sites 3, 8–13, and 59) was first subject to a narrow-interval survey where survey intervals were 3 meters in width. Surface artifacts and archaeological features were marked with pin flags to facilitate the refinement of the surface boundary that had been delimited for each site during the intensive pedestrian cultural resources survey and to facilitate the mapping of intrasite artifact and feature distributions, of individual surface-collected artifacts, and of evaluation phase excavation units. Mapping data were gathered electronically with a hand-held Trimble GeoXT submeter GPS unit.

Upon completion of the additional surface documentation, excavation was conducted on six (Sites 8–13) of the eight archaeological sites that were part of the field investigation. Sites were subject to different hand and mechanical excavation methods depending on the degree of prior landscape disturbance at each site and on the character of the archaeological deposits. Mechanical excavation was used on most sites in former agricultural fields to efficiently gauge and remove displaced plow zone sediments, and to assess the potential presence of intact archaeological features beneath the plow zone. Mechanical excavation was also thought to be particularly useful and appropriate for sites where the primary constituent of the material culture assemblage is fire-affected rock. The applicant and Energy Commission staff thought that there was a high likelihood that buried, intact fire features were present on such sites, and mechanical excavation was seen as an efficient method to verify that supposition. Hand excavation was used on archaeological sites where no prior landscape disturbance was apparent in order to document the intact stratigraphy of part of the project site, or, where the surface frequency of artifacts is relatively low, to ascertain the approximate depth of an archaeological deposit and to verify that a subsurface assemblage of artifacts on a site is consistent with its surface assemblage.

The archaeologists for the applicant mechanically excavated a pair of cross-trenches on each of four archaeological sites (Sites 8, 9, 11, and 12). A backhoe was used to excavate each trench to a length of approximately 10 meters and a depth never greater than 1 meter. Trenches were placed to capture cross-sections where the frequency of fire-affected rock is greatest. One profile drawing and a photograph was made of at least one wall of each trench. A plan-view drawing and a photograph was made for each archaeological feature exposed in each trench.

Hand excavation was done on two archaeological sites (Sites 10 and 13) using two different types of excavation units. Shovel test pits (STP) were excavated through Site 10 along perpendicular axes. The STPs were approximately 30 centimeters in diameter, were excavated in 10 centimeter increments, and typically reached a depth of 30 to 40 centimeters below the present surface of the site. All of the excavated sediments were dry-screened through ⅛-inch hardware cloth.

Test excavation units (TEU) were employed to investigate Site 13. Sixteen, 0.5-x-1-meter TEUs were excavated in a cross-trench configuration through the site's fire-affected rock concentration. One trench was 12 meters in length, and the other was 3.5 meters in length. One profile drawing and a photograph was made of at least one wall of each trench.

Results

The applicant argues, on the basis of archival research and prior surface observation, that 6 (BSPL-H-1, CA-KER-5264H, Site 16–19) of the 13 archaeological sites that the proposed project may impact are not eligible for listing in the CRHR. Archival research and further field observation of Site 3 and further field observation of Site 59 led the applicant to recommend neither site as being eligible for listing in the CRHR. The field investigation of five sites that include surface concentrations of fire-affected rock (Sites 8, 9, and 11–13) led to the discovery of six buried, intact hearth features, three of which were found, on the basis of radiocarbon assays, to range in age from 150 to 595 years old, and to the further discovery of charcoal-containing deposits that are approximately 810 years old. The discovery of the intact hearth features and the charcoal-containing deposits at Sites 8, 9, and 11–13 demonstrates the presence of buried archaeological deposits on the project site, and the absence of fire-affected rock on the present ground surface above many of the hearths indicates that buried archaeological deposits in the project area may often not manifest at the surface. These factors elevated staff concern about the extent of the distribution of buried archaeological deposits across the project area and was a significant factor in the development of Supplement to Data Request 34. The known presence and potential presence of intact features at Sites 8, 9, and 11–13 make the deposits historically significant in the context of Mojave Desert prehistory and have led the applicant to recommend them as being eligible for listing in the CRHR.

Archaeological Resources Evaluations

At this time, it appears that the proposed project may impact 18 archaeological resources. The resources include 13 archaeological sites in the project area that would be subject to direct impacts and 5 further archaeological sites in the project area that the applicant may need to actively avoid. Eleven of the 18 subject resources are prehistoric archaeological sites, 5 are historical archaeological sites, and 2 are multiple component archaeological sites that include both prehistoric and historic components.

Descriptions and evaluations of the historical significance of the 18 archaeological sites that the proposed project may impact are presented below, where the available information for each resource is sufficient. The information for the descriptions and evaluations is drawn from (Apple and Glenny 2008 and attachment 2 (DPR 523 series forms); Apple, Cleland, and Glenny 2008 and attachment 4(DPR 523 series forms)). The results of the geoarchaeology study (see "Geoarchaeology Study" subsection, above) promise to provide more reliable information on the physical contexts of the known archaeological sites in the project area, information critical to the interpretation of the historical significance of the surface expressions of these deposits. The study may also add additional archaeological sites to the cultural resources inventory of the proposed project site.

Prehistoric Archaeological Sites

Site 8

Site 8 is a prehistoric deposit of fire-affected rock[10] that includes one subsurface fire feature. The fire-affected rock and the feature occur in both surface and subsurface contexts. The site is on the floor of Fremont Valley in the east-central portion of the project site in a former agricultural field, now devoid of vegetation, which appears to have been subject to plowing.

The surface component of the site measures approximately 32 meters from northwest to southeast and 19 meters from northeast to southwest, and includes two concentrations of what are reported to be fire-affected rock and one "volcanic" stone flake. The concentrations are reported to be round and subangular clasts[11] of granite and basalt that are predominantly of cobble and pebble size. Some of the stone is noted to be cracked. Concentration 1, in the western half of the site, consists of approximately 350 pieces of fire-affected rock and measures approximately 12 meters from north to south and 10 meters from east to west. Concentration 2, approximately 3 meters east of Concentration 1, consists of approximately 150 pieces of fire-affected rock and measures approximately 5 meters from north to south and 7 meters from east to west. The archaeologists for the applicant attribute the apparently rather diffuse distribution of the fire-affected rock to past agricultural plowing.

The sedimentary deposits beneath the present surface of the site were examined using a pair of mechanically-excavated cross-trenches through Concentration 1. There was a 10.25-meter long, north-to-south trench through the concentration, and an 8.6-meter long, east-to-west trench that intersected the first trench at a 90 degree angle in the approximate center of Concentration 1. The trenches were approximately 1 meter wide and 1 meter deep.

The subsurface component of the site, now known as a result of the excavation of the cross-trenches, includes a single, partially intact archaeological feature, an apparent hearth. Hearth 1, found in the eastern wall of the north-to-south trench through

[10] Fire-affected rock is rock that has been thermally altered by exposure to fire. Thermal alteration of rock may manifest as orange to red patches of oxidation and sporadic black traces of charcoal on the exterior faces of rocks, and angular rock edges that may result from heat-induced cracking.

[11] Clasts are rock fragments produced by physical processes.

Concentration 1 and apparently later exposed in plan, was made up of 67 fire-affected rocks that measured 79 centimeters from north to south and 84 centimeters from east to west. The top of the feature was found 70 centimeters below the present surface of the project site and the base of the feature was 85 centimeters below that surface. Charcoal fragments of unreported size were found in the sediments directly above the feature. Charcoal (3.9 grams) is reported to have been gathered from the feature. An assay of that sample yielded a calibrated radiocarbon date of approximately 595 years before present (1950).

The physical context for Hearth 1 is unclear, because the broader stratigraphy of the project site is also presently unclear. Hearth 1 is reported to have been found in tan layers of silty sand and fine silty sand, apparently with no gravel, that are referred to respectively as “Root Zone” and “Lake Bed” deposits. The archaeologists for the applicant believe that agricultural plowing destroyed the original top 10 centimeters of the feature, but the pit for the feature nonetheless appears to have been originally dug from a former land surface now buried in the Root Zone deposits. The results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) may provide a more informative physical context for Hearth 1 and facilitate the association of the feature with other buried archaeological deposits nearby.

The archaeologists for the applicant recommend that Site 8 be found eligible for listing in the CRHR. The discovery of a buried, partially intact fire feature on the site and its association with the surface scatter of fire-affected rock make it likely that more such features are present at the site. Intact fire features are important units of archaeological analysis, because they have the potential to preserve organic residues that may inform our understanding of prehistoric patterns of natural resource selection and use, because they inform our understanding of prehistoric resource preparation technology, and because they provide datable material that places such information in time. The investigation of such features may also offer the opportunity to identify and document the former land surfaces that once surrounded the features and the contemporary material assemblages that may be present on those surfaces, and thereby inform our understanding of the broader behavioral contexts of which the fire features are a part. The above considerations, in combination with the relative general scarcity of buried, intact archaeological deposits in the Mojave Desert, lead staff to recommend that Site 8 is eligible for listing in the CRHR under Criterion 4, because the resource has yielded and has the potential to yield information important to the Late Prehistoric period prehistory of the western Mojave Desert.

Site 9

Site 9 is a prehistoric deposit of fire-affected rock that includes one subsurface fire feature. The fire-affected rock and the feature occur in both surface and subsurface contexts. The site is on the floor of Fremont Valley in the northeastern portion of the project site in a former agricultural field, now devoid of vegetation, which appears to have been subject to plowing.

The surface component of the site, a scatter of fire-affected rock, measures approximately 10 meters from north to south and 10 meters from east to west. No other cultural material was found in or near the scatter. The fire-affected rock is reported to include approximately 150 rounded, subangular, and angular, fire-blackened clasts of granitic rock that range from large pebbles to small cobbles in size. The archaeologists for the applicant partially attribute the distribution of the fire-affected rock to past agricultural plowing, and partially to forces of erosion which appear to have transported some of the rock downslope and toward the north.

The sedimentary deposits beneath the present surface of the site were examined using a pair of mechanically-excavated cross-trenches through the approximate center of the site. There was a 7.2-meter long, north-to-south trench through the rock scatter, and an 8.2-meter long, east-to-west trench that intersected the first trench at a 90 degree angle. The trenches were approximately 1 meter wide and 1 meter deep.

The subsurface component of the site, now known as a result of the excavation of the cross-trenches, includes a single archaeological feature, an apparent hearth. Hearth 1, found in the western wall of the north-to-south trench, is a shallow earthen pit the outline of which is made more apparent by a discontiguous band of charcoal-stained, pinkish, oxidized sediments. The interior of the pit is filled with a deposit of medium brown, charcoal-stained, silty sand. The top of the feature was found 25 centimeters below the present surface of the project site and the base of the feature was 35 centimeters below that surface. The diameter of the feature, in the trench wall, was 1.9 meters. No charcoal or flotation samples were taken from the feature or the feature fill.

The physical context for Hearth 1 is unclear, because the broader stratigraphy of the project site is also presently unclear. Hearth 1 is reported to have been found in tan layers of silty sand, apparently with no gravel, that are referred to respectively as “Plow Zone” and “Root Zone” deposits. The feature pit appears to have been originally dug from a former land surface now buried in the Plow Zone deposits down into the upper portion of the Root Zone deposits. The results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) may provide a more informative physical context for Hearth 1 and facilitate the association of the feature with other buried archaeological deposits nearby.

The archaeologists for the applicant recommend that Site 9 be found eligible for listing in the CRHR. The discovery on the site of a buried fire feature that retains good integrity and its association with the surface scatter of fire-affected rock make it likely that more and potentially different types of fire features are present at the site. Intact fire features are important units of archaeological analysis, because they have the potential to preserve organic residues that may inform our understanding of prehistoric patterns of natural resource selection and use, because they inform our understanding of prehistoric resource preparation technology, and because they provide datable material that places such information in time. The investigation of such features may also offer the opportunity to identify and document the former land surfaces that once surrounded the features and the contemporary material assemblages that may be present on those surfaces, and thereby inform our understanding of the broader behavioral contexts of which the fire features are a part. The above considerations, in combination with the relative general scarcity of buried, intact archaeological deposits in the Mojave Desert, lead staff to recommend that Site 9 is eligible for listing in the CRHR under Criterion 4, because the resource has yielded and has the potential to yield information important to the prehistory of the western Mojave Desert.

Site 10

Site 10 is a prehistoric lithic deposit that includes four partial bifaces[12], one utilized flake, one core, one handstone or mano fragment, and approximately 32 stone flakes. The lithic artifacts were found in both surface and subsurface contexts. The site is on the higher surface to the southeast of the Garlock Fault in the east-central portion of the project site. The present surface of the site is reported to have a shallow slope gradient that drops toward the north, and remnant plow furrows along that axis attest to the former use of the land for agriculture. The archaeologists for the applicant report that erosive forces have redistributed artifacts downslope. The site surface is said to be deflated and of a "sandy, clayey soil." Almost no vegetation was apparent on the site in August, 2008.

The surface component of the site is a sparse (~1 piece/62 square meters) scatter of prehistoric lithics, stone tools and stone tool manufacturing debris. The scatter measures approximately 60 meters from northeast to southwest and 38 meters from northwest to southeast.

The surface lithic assemblage on the site includes four partial bifaces, one utilized flake, one core, one handstone or mano fragment, and approximately 30 stone flakes or pieces of lithic debitage. The fragmentary bifaces are all of cryptocrystalline silicate[13] (CCS), three of the four fragments are reported to be yellow, and they appear to represent different stages of manufacture. The archaeologists for the applicant interpret three of the four bifaces to have been broken prior to completion and the fourth to have been broken during maintenance work on that piece. The fragments range in size from 2.5 to 5.7 centimeters in length. The debitage on the site surface is of CCS. The further character of the debitage is unreported. The character of the utilized flake, the core, and the mano fragment are unreported.

The sedimentary deposits beneath the present surface of the site were examined using two intersecting rows of 11 hand-excavated STPs through the approximate center of the site. Six STPs were excavated in a north-to-south row at 20-meter intervals and a row of four STPs were excavated in 20-meter intervals in an east-to-west row that intersected the approximate middle of the north-to-south row. An eleventh STP was excavated between two of the STPs along the north-to-south row. The STPs were approximately 30 centimeters in diameter, were excavated in 10 centimeter increments, and typically reached a depth of 30 to 40 centimeters below the present surface of the site.

The subsurface component of the site, now known as a result of the excavation of the STPs, includes two stone flakes. Both flakes came from the same STP in the approximate center of the site. One was found from 10 to 20 centimeters below the present surface, and the other was from 20 to 30 centimeters below the surface. The flakes are of CCS and of unreported color. The archaeologists for the applicant interpret both flakes to be biface thinning flakes.

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[12] A biface is a stone tool that exhibits two shaped surfaces.

[13] Cryptocrystalline silicates are rocks such as flint, chert, chalcedony, or jasper that contain a high percentage of silica (SiO^2), the primary compound that composes quartz.

The physical contexts for the two subsurface flakes are unclear, because the broader stratigraphy of the project site is also presently unclear. The stratigraphic contexts for the flakes are unreported. The results of the geoarchaeology study (see "Geoarchaeology Study" subsection, above) may provide more informative physical contexts for the flakes and facilitate the association of the artifacts with other buried archaeological deposits nearby.

The archaeologists for the applicant recommend that Site 10, interpreted by the archaeologists to have been a campsite, be found ineligible for listing in the CRHR. The sparse character of the surface component of the site and the apparent relative absence of a subsurface component in combination with the apparent absence of cultural material that would facilitate the placement of the deposit in time indicates that the site does not have the potential to yield information important to prehistory. The above considerations lead staff to recommend that Site 10 is not eligible for listing in the CRHR.

Site 11

Site 11 is a prehistoric deposit of fire-affected rock that includes three subsurface fire features and one bone fragment. The features and the bone were found in both surface and subsurface contexts. The site is on the floor of Fremont Valley in the northeastern portion of the project site in a former agricultural field which appears to have been subject to plowing. The vegetation on the site in August, 2008 was limited to intermittent patches of an unreported species of short desert grass. The archaeologists for the applicant note a sparse lag deposit[14] of rock on the land surface where the site is found.

The surface component of the site, a scatter of fire-affected rock, measures approximately 16 meters from north to south and 8 meters from east to west. No other cultural material was found in or near the scatter. The fire-affected rock is reported to include approximately 230 subangular clasts of granitic rock that range from medium pebbles to small cobbles in size. The archaeologists for the applicant attribute the distribution of the fire-affected rock to past agricultural plowing.

The sedimentary deposits beneath the present surface of the site were examined using a pair of mechanically-excavated cross-trenches through the approximate center of the site. There was a 16.4-meter long, north-to-south trench through the rock scatter, and a 9-meter long, east-to-west trench that intersected the first trench at a 90-degree angle. The trenches were approximately 1 meter wide and 1 meter deep.

The subsurface component of the site, now known as a result of the excavation of the cross-trenches, includes three, apparently intact, archaeological features that the archaeologists for the applicant interpret to be hearths, Hearths 1–3. Hearth 1 was found in the western wall of the north-to-south trench, south of the east-to-west trench, and was apparently later exposed in plan. The feature was made up of 30 fire-affected rocks in a roughly circular, 46-centimeter in diameter arrangement inside a broader area of ash and charcoal-stained sediments. The overall dimensions of the feature, the fire-

[14] Residual accumulation of coarse, unconsolidated rock and mineral debris left behind by the winnowing of finer material.

affected rock arrangement and the broader area of ash and charcoal-stained sediments, was 86 centimeters from north to south and 55 centimeters from east to west. The top of the feature was found 30 centimeters below the present surface of the project site and the base of the feature was 55 centimeters below that surface. Charcoal fragments of unreported size and a single bird bone fragment were found in the feature. Charcoal (50 grams) is reported to have been gathered from the feature. An assay of that sample yielded calibrated radiocarbon dates of approximately either 655 or 580 years before present (1950)[15].

Hearth 2 was found in the north-to-south trench, south of the east-to-west trench. The feature was reported to be 0.5 meters north of Hearth 1 and was exposed in plan. Hearth 2 was apparently made up of 35 fire-affected rocks in a roughly circular arrangement, measuring 42 centimeters north to south and 62 centimeters east to west, inside a broader depression. Overall, the fire-affected rock arrangement and the broader depression were 85 centimeters in diameter. The top of the feature was found 25 centimeters below the present surface of the project site, and the base of the feature was 40 centimeters below that surface. Charcoal fragments of unreported size and a single bird bone fragment were found in the feature. Charcoal (67.9 grams) is reported to have been gathered from the feature.

Hearth 3 was found in the southern wall of the east-to-west trench, east of the north-to-south trench. The feature is depicted in Figure 5 of the report for the evaluation program (Apple, Cleland, and Glenny 2008) to be approximately 5.6 meters east-northeast of Hearth 2. Hearth 3 appears to be an earthen pit the outline of which is made more apparent by discontiguous bands of charcoal-stained, pinkish, oxidized sediments. No fire-affected rocks are reported for the feature. The top of the feature was found 13 centimeters below the present surface of the project site, and the base of the feature was 25 centimeters below that surface. The diameter of the feature, in the trench wall, was 45 centimeters.

The physical contexts for Hearths 1–3 are unclear, because the broader stratigraphy of the project site is also presently unclear. Hearths 1–3 are reported to have been found in tan layers of silty sand, apparently with no gravel, that are referred to respectively as “Plow Zone” and “Root Zone” deposits. The feature pits appear to have been originally dug from former land surfaces now buried in the “Plow Zone” deposits down into the upper portion of the “Root Zone” deposits. The results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) may provide more informative physical contexts for Hearths 1–3 and facilitate the association of the features with each other and with other buried archaeological deposits nearby.

The archaeologists for the applicant recommend that Site11 be found eligible for listing in the CRHR. The discovery of three buried, intact fire features on the site and its association with the surface scatter of fire-affected rock make it likely that more such features are present at the site. Intact fire features are important units of archaeological analysis, because they have the potential to preserve organic residues that may inform our understanding of prehistoric patterns of natural resource selection and use, because

[15] The fact that the results of the assay provide multiple possible ages for the sample is a function of the results of the calibration process.

they inform our understanding of prehistoric resource preparation technology, and because they provide datable material that places such information in time. The investigation of such features may also offer the opportunity to identify and document the former land surfaces that once surrounded the features and the contemporary material assemblages that may be present on those surfaces, and thereby inform our understanding of the broader behavioral contexts of which the fire features are a part. The above considerations, in combination with the relative general scarcity of buried, intact archaeological deposits in the Mojave Desert, lead staff to recommend that Site 11 is eligible for listing in the CRHR under Criterion 4, because the resource has yielded and has the potential to yield information important to the Late Prehistoric period prehistory of the western Mojave Desert.

Site 12

Site 12 is a prehistoric deposit of fire-affected rock that includes one subsurface fire feature, one handstone or mano fragment, and one stone flake. The feature and the artifacts were found in both surface and subsurface contexts. The site is on the floor of Fremont Valley in the northeastern portion of the project site in a former agricultural field which appears to have been subject to plowing. The vegetation on the site in August, 2008 was limited to an unreported species of dry grass.

The surface component of the site measures approximately 25 meters from northeast to southwest and 14 meters from northwest to southeast, and includes two concentrations of what are reported to be fire-affected rock, the mano fragment, and the stone flake. The concentrations are reported to be round and subangular clasts of granite and basalt that range predominantly from medium pebbles to small cobbles in size. The stone is noted to be fire-blackened and cracked. Concentration 1, in the southwestern portion of the site, consists of approximately 330 pieces of fire-affected rock and measures approximately 10 meters from north to south and 12 meters from east to west. Concentration 2, adjacent to and to the northeast of Concentration 1, consists of approximately 250 pieces of fire-affected rock and measures approximately 12 meters from north to south and 8 meters from east to west. The archaeologists for the applicant report that plowing has scattered the fire-affected rock along a northeast to southwest axis.

The surface artifact assemblage for Site 12, the mano fragment and the stone flake, are the only evidence of the character of the use of the site beyond the fire-affected rock concentrations and Hearth 1. The mano fragment is an unshaped, unifacially ground, broken cobble of granitic rock that appears to have been found in the southwestern portion of Concentration 2. The flake, of unreported character, was found adjacent to the western boundary of Concentration 1.

The sedimentary deposits beneath the present surface of the site were examined using pairs of mechanically-excavated cross-trenches through Concentrations 1 and 2. There was a 14-meter long, north-to-south trench through Concentration 1, and a 12.5-meter long, east-to-west trench that intersected the first trench at a 90 degree angle in the approximate center of Concentration 1. There was a 13.3-meter long, north-to-south trench through Concentration 2, and an 8.5-meter long, east-to-west trench that intersected the first trench at a 90 degree angle in the approximate center of Concentration 2. All trenches were approximately 1 meter wide and 1 meter deep.

The subsurface component of the site, now known as a result of the excavation of the cross-trenches, includes a single intact archaeological feature, an apparent hearth. Hearth 1 was found in the floor of the east-to-west trench through Concentration 1 just west of the intersection of that trench with the north-to-south trench through the concentration. The feature was made up of four fire-affected rocks of medium cobble size inside an earthen pit the bottom of which was apparent as charcoal-stained, reddish, oxidized sediments. The fire-affected rocks were embedded in a sedimentary matrix that included charcoal fragments of unreported size. The overall dimensions of the feature, the fire-affected rocks and the broader pit, was 46 centimeters from north to south and 46 centimeters from east to west. The top of the feature was found 36.5 centimeters below the present surface of the project site and the base of the feature was 50 centimeters below that surface. Charcoal (13 grams) is reported to have been gathered from the feature. An assay of that sample yielded a calibrated radiocarbon date of approximately 150 years before present (1950).

The physical context for Hearth 1 is unclear, because the broader stratigraphy of the project site is also presently unclear. Hearth 1 is reported to have been found in layers of silty sand referred to clearly, only as “stratigraphic layers I and II.” The results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) may provide a more informative physical context for Hearth 1 and facilitate the association of the feature with other buried archaeological deposits nearby.

The archaeologists for the applicant recommend that Site 12 be found eligible for listing in the CRHR. The discovery of a buried intact fire feature on the site and its association with the surface scatter of fire-affected rock make it likely that more such features are present at the site. Intact fire features are important units of archaeological analysis, because they have the potential to preserve organic residues that may inform our understanding of prehistoric patterns of natural resource selection and use, because they inform our understanding of prehistoric resource preparation technology, and because they provide datable material that places such information in time. The investigation of such features may also offer the opportunity to identify and document the former land surfaces that once surrounded the features and the contemporary material assemblages that may be present on those surfaces, and thereby inform our understanding of the broader behavioral contexts of which the fire features are a part. The above considerations, in combination with the relative general scarcity of buried, intact archaeological deposits in the Mojave Desert, lead staff to recommend that Site 12 is eligible for listing in the CRHR under Criterion 4, because the resource has yielded and has the potential to yield information important to the Late Prehistoric period prehistory of the western Mojave Desert.

Site 13

Site 13 is a prehistoric deposit of fire-affected rock that includes one millingstone or metate fragment, one biface fragment, one stone flake, and bone. The artifacts were found in both surface and subsurface contexts. The site is on the floor of Fremont Valley in the northwestern portion of the project site in an area where the intermittent pooling of water and the relatively high clay content of surface sediments produce polygonal mud cracks at the surface. Creosote (*Larrea tridentata*) and an unreported desert grass species are reported to have been the predominant vegetation on the site in August, 2008.

The primary surface component of the site, a scatter of fire-affected rock, measures approximately 31 meters from north to south and 35 meters from east to west, and includes the metate fragment and the fragmentary biface. The fire-affected rock is reported to include approximately 25 rounded, subangular, and angular clasts of fire-blackened and cracked granite and schist that range from medium pebbles to small cobbles in size.

The metate fragment and the fragmentary biface are the only shaped artifacts in the fire-affected rock scatter on the present surface of the site. The metate fragment is reported to be of “volcanic material.” The fragment is of small cobble size, and has remnants of two different ground surfaces which are perpendicular to one another. One of the ground surfaces exhibits peck marks, indicative of grinding surface rejuvenation. The metate fragment provides no evidence as to whether the complete implement had been shaped. The fragmentary biface is of obsidian. The artifact is 4.5 centimeters in length, 2.2 centimeters in width, and 0.8 centimeters thick. The archaeologists for the consultant identify it as a tip and midsection fragment with a bending break through the midsection. The archaeologists interpret the piece as a being unfinished and broken during manufacture. The artifact was subject to x-ray fluorescence analysis to ascertain the probable source of the obsidian of which the piece was made. The results of the analysis indicate that Sugarloaf Mountain in the Coso Volcanic Field, roughly 60 miles north-northeast of the project area, is the likely source of the obsidian. The artifact was also subject to obsidian band hydration analysis to facilitate a determination of the age of the manufacture of the piece. The result of the analysis is that the biface fragment was found to have a mean hydration band measurement of 5.9 microns. The archaeologists for the consultant interpret this mean measurement to indicate a relatively crude date of manufacture sometime from the late Gypsum to the Rose Spring complex, roughly 2,500 to 900 years ago.

The sedimentary deposits beneath the present surface of the site were examined using a pair of hand-excavated cross-trenches near the center of the site. There was a 12-meter long, north-to-south trench through the rock scatter, and a 3.5-meter long, east-to-west trench to the east of the first trench that terminated in the latter trench at a 90 degree angle. The trenches, excavated as series of contiguous TEUs, were 0.5-meters wide and were excavated to an unreported depth of at least 40 centimeters.

The examination of the subsurface component of the site yielded charcoal, fire-affected rock, a stone flake, and bone. Charcoal of unreported size was found scattered throughout the deposits exposed in the trenches from 0 to 40 centimeters below the present surface. A sample of charcoal (0.1 grams) was gathered from 0 to 10 centimeters below the present surface in the northern part of the north-to-south trench. An assay of that sample yielded a calibrated radiocarbon date of approximately 810 years before present (1950). Fire-affected rock appears to have been found below the surface in twelve of the TEUs. Bone of unreported character was found in three of the TEUs. The stone flake is reported to be of “volcanic” stone and was found from 0 to 10 centimeters below the present surface in the southern part of the north-to-south trench. The flake was apparently 3.1 centimeters in length and the archaeologists for the applicant interpret the artifact to be a core reduction flake.

The physical contexts for the material culture of the subsurface component are unclear, because the broader stratigraphy of the project site is also presently unclear. The subsurface sedimentary deposits of the Site 13 are only reported to be silty sand. The results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) may provide more informative physical contexts for the materials and facilitate their association with other buried archaeological deposits nearby.

The archaeologists for the applicant recommend that Site 13 be found eligible for listing in the CRHR. The surface and subsurface scatter of fire-affected rock and the wide subsurface distribution of charcoal make it likely that fire features such as those at Sites 8, 9, 11, and 12 are also present at Site 13. Intact fire features are important units of archaeological analysis, because they have the potential to preserve organic residues that may inform our understanding of prehistoric patterns of natural resource selection and use, because they inform our understanding of prehistoric resource preparation technology, and because they provide datable material that places such information in time. The investigation of such features may also offer the opportunity to identify and document the former land surfaces that once surrounded the features and the contemporary material assemblages that may be present on those surfaces, and thereby inform our understanding of the broader behavioral contexts of which the fire features are a part. The above considerations, in combination with the relative general scarcity of buried, intact archaeological deposits in the Mojave Desert, lead staff to recommend that 13 is eligible for listing in the CRHR under Criterion 4, because the resource has yielded and has the potential to yield information important to the Late Prehistoric period prehistory of the western Mojave Desert.

Site 17

Site 17 is a sparse (1 piece/75 square meters) prehistoric lithic scatter that measures approximately 20 meters from north to south and 15 meters from east to west, and includes one biface, one utilized flake, and two stone flakes. The artifacts were found on the surface of the site, which is in a fallow agricultural field in the southwestern portion of the project site. The present site surface is reported to be deflated and to have a gravel lag deposit. The vegetation on the site in November, 2007, a sparse cover of unreported shrub and grass species, facilitates the formation of small coppice dunes on the site surface. The archaeologists for the applicant note that a more consolidated ground surface appears to be beneath the looser surface sediments and that the site surface appears to have been subject to plowing.

The site artifact assemblage includes one biface, one utilized flake, and two stone flakes. The four pieces are of CCS and of unreported color. The utilized flake and the biface are reported to exhibit use wear. The further character of any of the four artifacts is unreported.

The physical context for the surface artifact assemblage at Site 17 is unclear, because the broader geomorphic context of the project site is also presently unclear. The results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) may provide a more informative physical context for the assemblage and facilitate the association of the artifacts with other archaeological deposits nearby.

The archaeologists for the applicant recommend that Site 17, interpreted by the archaeologists to have been a temporary camp, be found ineligible for listing in the CRHR. The sparse character of the surface assemblage in combination with the apparent absence of cultural material that would facilitate the placement of the deposit in time would appear to indicate that the site does not have the potential to yield information important to prehistory. Staff, however, awaits the results of the geoarchaeology study before recommending whether Site 17 is eligible for listing in the CRHR. Absent a better understanding of the landscape context for the archaeological site and absent any examination of the sedimentary deposits beneath the surface artifact assemblage, staff believes a determination of the historical significance of the site would be premature.

Site 18

Site 18 is an extremely sparse (1 piece/135 square meters) prehistoric lithic scatter that measures approximately 18 meters from north to south and 45 meters from east to west, and includes one core chopper, one core fragment, and four stone flakes. The artifacts were found on the surface of the site, which is in a fallow agricultural field in the southwestern portion of the project site. The present site surface is reported to be deflated and to have a gravel lag deposit. There are what appear to be three relatively long (6–13 meters), transverse sand dunes along the northern and southern site boundary. The long axes of the dunes are oriented on a roughly northeast to southwest axis with slipfaces that appear to point roughly to the southeast. The vegetation on the site in November, 2007, an extremely sparse cover of an unreported species of small bunch grass, also facilitates the formation of small coppice dunes on the site surface.

The site artifact assemblage includes one core chopper, one core fragment, and four stone flakes. The four stone flakes are of CCS and of unreported color. The further character of any of the six artifacts is unreported.

The physical context for the surface artifact assemblage at Site 18 is unclear, because the broader geomorphic context of the project site is also presently unclear. The results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) may provide a more informative physical context for the assemblage and facilitate the association of the artifacts with other archaeological deposits nearby.

The archaeologists for the applicant recommend that Site 18 be found ineligible for listing in the CRHR. The extremely sparse character of the surface assemblage in combination with the apparent absence of cultural material that would facilitate the placement of the deposit in time would appear to indicate that the site does not have the potential to yield information important to prehistory. Staff, however, awaits the results of the geoarchaeology study before recommending whether Site 18 is eligible for listing in the CRHR. Absent a better understanding of the landscape context for the archaeological site and absent any examination of the sedimentary deposits beneath the surface artifact assemblage, staff believes a determination of the historical significance of the site would be premature.

Site 19

Site 19 is a sparse (~1 piece/76 square meters) prehistoric lithic scatter that measures approximately 13 meters from north to south and 35 meters from east to west, and includes six stone flakes. The artifacts were found on the surface of the site, which is in a fallow agricultural field in the southwestern portion of the project site. The present site surface is reported to be deflated and to have a relatively substantial gravel lag deposit. The vegetation on the site in November, 2007, sparse patches of an unreported grass species, facilitates the formation of short (~50 centimeters) coppice dunes on the site surface. The archaeologists for the applicant note that the site surface appears to have been subject to plowing.

The site artifact assemblage includes six stone flakes. The six pieces are of CCS. The further character of the flakes is unreported.

The physical context for the surface artifact assemblage at Site 19 is unclear, because the broader geomorphic context of the project site is also presently unclear. The results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) may provide a more informative physical context for the assemblage and facilitate the association of the artifacts with other archaeological deposits nearby.

The archaeologists for the applicant recommend that Site 19 be found ineligible for listing in the CRHR. The sparse character of the surface assemblage in combination with the apparent absence of cultural material that would facilitate the placement of the deposit in time would appear to indicate that the site does not have the potential to yield information important to prehistory. Staff, however, awaits the results of the geoarchaeology study before recommending whether Site 19 is eligible for listing in the CRHR. Absent a better understanding of the landscape context for the archaeological site and absent any examination of the sedimentary deposits beneath the surface artifact assemblage, staff believes a determination of the historical significance of the site would be premature.

Site 54

Site 54 is a sparse (1 piece/50 square meters) prehistoric lithic scatter that measures approximately 20 meters from north to south and 30 meters from east to west, and includes one core, one modified flake, and ten stone flakes. The artifacts were found on the surface of the site approximately one mile west of the project site and approximately 0.4 mile west of SR 14. The present site surface appears to be on a mid- to lower slope of the Pine Tree Canyon alluvial fan. The predominant vegetation type on the site appears to be Mojave creosote bush scrub.

The site artifact assemblage includes one core, one modified flake, and ten stone flakes. The pieces are all of CCS. The further character of the artifacts is unreported.

The physical context for the surface artifact assemblage at Site 54 is unclear, because the broader geomorphic context of the project area is also presently unclear. The results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) may provide a more informative physical context for the assemblage and facilitate the association of the artifacts with other archaeological deposits nearby.

The archaeologists for the applicant make the unsupported assertion in the inventory report (Apple and Glenny 2008, p. 52) that Site 54 has the potential to yield information important to prehistoric lithic technology in the western Mojave Desert and is, therefore, potentially eligible for listing in the CRHR under Criterion 4. Staff presently abstains, absent a rationale for the above assertion and absent more information on the physical character of the Site 54 deposit, from recommending whether Site 54 is eligible for listing in the CRHR. Staff anticipates that further consultation with the applicant and the preliminary results of the geoarchaeology study will enable the development of a CRHR-eligibility recommendation for the site prior to the publication of the FSA.

Site 59

Site 59 appears to be a prehistoric trail. The trail is approximately one mile to the west-southwest of the project site and approximately one-tenth of one mile west of SR 14, and runs approximately north-northeast to south-southwest. It occurs in two segments. The southern terminus of the southern segment is Site 40, which appears to be previously recorded archaeological site CA-KER-2142H. The trail runs north-northeast from CA-KER-2142H for approximately 1.5 kilometers and fades into the landscape. Approximately 200 meters north of the northern terminus of the southern trail segment, the northern trail segment begins and runs another approximately 1.3 kilometers to the north-northeast where it again fades into the landscape. The trail is approximately 30 to 35 centimeters in width. Erosion and heavy off-highway vehicle activity have destroyed portions of both trail segments. No cultural materials were found as a result of the close-interval pedestrian survey along the trail. The trail appears to traverse mid-to-lower slopes of the Pine Tree Canyon alluvial fan. The predominant vegetation type on the site appears to be Mojave Creosote Bush Scrub.

The archaeologists for the applicant make the unsupported assertion that Site 59 does not have the potential to yield information important to the prehistory of the western Mojave Desert and is, therefore, not eligible for listing in the CRHR under Criterion 4. Staff presently abstains, absent a more thoroughly documented and explicit rationale for the above assertion, from recommending whether Site 59 is eligible for listing in the CRHR. Site 59 most likely represents two segments of an extensive prehistoric trail system that winds along the southern bases of the Tehachapi and Sierra Nevada Mountains through prehistoric archaeological sites similar to the prehistoric component of CA-KER-2142H, which includes assemblages of ground and chipped stone artifacts and partially buried fire features among two areas of apparently discolored anthropogenic sediments. Staff anticipates that the applicant will reconsider the historical significance of Site 59 prior to the publication of the FSA and include a discussion of whether the recorded trail segments may contribute to the historical significance of a broader trail system.

Historical Archaeological Sites

BSPL-H-1

BSPL-H-1 is a historic refuse deposit approximately three miles south-southeast of the project site and approximately 20 meters east of Neuralia Road, the proposed location for the natural gas pipeline to the proposed project. The deposit appears to be a surface phenomenon and measures approximately 50 meters from north to south and 55 meters from east to west. The vegetation on the site in December, 2007 is reported as sparse creosote with burro grass and bottle brush also present. The archaeologists for the applicant state that site artifacts have been redistributed by wind and sheet wash and that the site surface is deflated.

The site artifact assemblage includes approximately 70 tin cans and tin can fragments, and glass, ceramic, and metal fragments. The tin can assemblage is reported to include hole-in-top and sanitary cans, and tobacco tins. The glass assemblage is reported to include fragments of milk glass, and fragments of manganese-decolorized, aqua, brown, green, and clear glass. The ceramic assemblage is reported to include fragments of white and green ceramics. The further character, and the absolute or relative quantity of any of the artifact types in any of the assemblages are unreported.

The archaeologists for the applicant recommend that BSPL-H-1, interpreted by the archaeologists to reflect multiple roadside dumping events from the 1920s through the 1960s, be found ineligible for listing in the CRHR, primarily due to the difficulty in associating the deposit with important historic themes or persons. While the resolution of the documentation for the deposit makes it difficult to assess the actual date range that it represents and, hence, its potential association with important historic themes, staff nonetheless recommends that BSPL-H-1 is not eligible for listing in the CRHR, because it is highly improbable that the deposit would ever be able to yield information important to the early twentieth century history of the western Mojave Desert.

BSPL-H-2

BSPL-H-2 is a historical archaeological site that includes two concrete foundations and a nearby refuse deposit. The site is approximately four miles south-southeast of the project site and approximately 20 meters east of Neuralia Road, the proposed location for the natural gas pipeline to the proposed project. The site appears to be largely a surface phenomenon and measures approximately 25 meters from north to south and 15 meters from east to west. The vegetation on the site in December, 2007 is reported to be predominantly creosote with burro grass and bottle brush also present. The archaeologists for the applicant cite the presence of silty sand on the site surface as evidence of surface deflation by sheet wash.

The archaeological features on the site include two weathered and cracked concrete foundations, a larger one toward the northern end of the site and a smaller one approximately ten meters to the southwest of the larger one. Five-eighth-inch threaded bolts appear to be set into and along the perimeter of both foundations, and both foundations appear to have local aggregate in the foundation concrete. There is a set of four steps on the northern side of the larger foundation that leads down into a basement. The archaeologists for the applicant surmise that the smaller foundation may have been for a cistern or a septic tank. The type, the form, the character, and the dimensions of the foundations are unreported.

The artifact assemblage that is the refuse deposit is reported to include glass, cans, ceramics, and metal. The archaeologists for the applicant note the presence of manganese-decolorized glass, hole-in-top cans, and barbed wire. The further character, or the absolute or relative quantity of any of the artifact types in any of the assemblages is unreported.

The archaeologists for the applicant make the assertion in the inventory report (Apple and Glenny 2008, p. 54), on the basis of the presence of the concrete foundations and the refuse deposit, the potential presence of other refuse-filled features, and the nonspecific potential to provide information not in the archival record, that BSPL-H-2 has the potential to yield information important to the late nineteenth- and early twentieth-century history of the western Mojave Desert and is, therefore, potentially eligible for listing in the CRHR under Criterion 4. Staff presently abstains, absent a more explicit rationale for the above assertion and absent more information on the physical character of BSPL-H-2, from recommending whether BSPL-H-2 is eligible for listing in the CRHR. Staff anticipates that further consultation with the applicant and the preliminary results of the geoarchaeology study will enable the development of a CRHR-eligibility recommendation for the site prior to the publication of the FSA.

CA-KER-5264H

CA-KER-5264H was a historic-period, surficial refuse deposit in the northern portion of the project site. The archaeologists for the applicant were unable to relocate the site during the recent intensive pedestrian cultural resources survey and suggest that the artifacts that originally made up the deposit may have been entirely collected at the time of the original recordation of the site in 1997.

Staff recommends the dismissal of CA-KER-5264H from further consideration in the present siting case, because it no longer appears to exist.

Site 16

Site 16 is a historic refuse deposit near the center of the project site. The deposit appears to be a surface phenomenon in a fallow agricultural field, and measures approximately 20 meters from north to south and 15 meters from east to west. The site is devoid of vegetation. The archaeologists for the applicant note that the site surface appears to have been subject to plowing.

The site artifact assemblage includes glass, ceramics, metal, automobile parts, and a can opener. The glass assemblage is reported to include one whole bottle with a stopper finish, fragments of milk glass, and fragments of aqua, brown, and green glass. The metal assemblage includes non-diagnostic metal fragments. The further character, or the absolute or relative quantity of any of the artifact types in any of the assemblages is unreported.

The archaeologists for the applicant recommend that Site 16, interpreted by the archaeologists to reflect multiple dumping events in the historic and recent past, be found ineligible for listing in the CRHR, primarily due to the difficulty in associating the deposit with important historic themes or persons. The resolution of the documentation for the deposit makes it difficult to assess the date range and, hence, its potential association with important historic themes. Staff therefore presently abstains, absent more information on the artifacts of the deposit, from recommending whether Site 16 is eligible for listing in the CRHR. Staff anticipates that further consultation with the applicant will enable the development of a CRHR-eligibility recommendation for the site prior to the publication of the FSA.

Multiple Component Archaeological Sites

Site 3

Site 3 is an oblong archaeological deposit that includes both prehistoric and historic components. The deposit is approximately three-quarters of mile to the west of the project site and 300 feet west of SR 14. The long axis of the deposit parallels and is adjacent to an improved dirt road that runs roughly northwest from SR 14 to a nearby electrical substation. The prehistoric component appears to be a surface phenomenon, while the historic component appears to occur in both surface and subsurface contexts. The present site surface appears to be on a mid-to-lower slope of the Pine Tree Canyon alluvial fan. The predominant vegetation type on the site appears to be Mojave Creosote Bush Scrub.

The surface component of the site measures approximately 127 meters from northwest to southeast and 37 meters from northeast to southwest, and includes three concentrations of predominantly historic artifacts, which appear to be partially buried. Surface observations of the concentrations suggest that shallow depressions may have been mechanically excavated through the gravelly deposits on this portion of the Pine Tree Canyon alluvial fan, filled with historic refuse, and then partially buried with the excavated dirt and gravel. The archaeologists for the applicant note that construction-related debris and miscellaneous hardware dominate the overall artifact assemblage of the concentrations, although household refuse is present.

Concentration 1, the most northwesterly of the three concentrations on the site, includes the entire prehistoric component of the site, in addition to a concentration of historic artifacts. The concentration measures 5.5 meters from north to south and 6 meters from east to west. The prehistoric component is a sparse scatter of 10 artifacts which includes 1 core, 1 unmodified nodule of obsidian, and 8 stone flakes. The further character of the artifacts is unreported. The historic component of Concentration 1 includes glass, ceramic, tin can, wood, and metal assemblages, and automobile parts. The glass assemblage includes what is reported to be a wine bottle fragment, 11 fragments of flat (window) glass of unreported color, 2 fragments of aqua glass, and 15 fragments of what are reported to be pink frosted glass. The ceramic assemblage is reported as polychrome, glazed, and earthenware fragments. The tin can assemblage includes what is reported to be a Prince Albert tobacco tin and modern food tins (sanitary cans) of unreported character. The wood assemblage is milled lumber of unreported quantity, dimensions, or finish. The metal assemblage includes 1 metal spike, crown caps, 1 gun cartridge, 1 spring, and 15 wire nails. The automobile parts include tire fragments, one air filter, one hose, and an unreported quantity of nuts. The further character of the artifacts in Concentration 1 is unreported.

Concentration 2, approximately 41 meters southeast of Concentration 1, is a historic refuse deposit and measures approximately 4 meters from north to south and 3 meters from east to west. The concentration includes glass, ceramic, tin can, and metal assemblages, and automobile parts. The glass assemblage includes one Delaware Punch bottle fragment with the embossed date of “March 4 1924” (bottle patent date), and two fragments of brown glass. The ceramic assemblage appears to be reported as three glazed ceramic tile fragments. The tin can assemblage is reported to be a Prince Albert tobacco tin. The metal assemblage is four wire nails and an unreported quantity or type of wire mesh. The balance of the reported portion of the concentration is reported as miscellaneous car parts. The further character of the artifacts in Concentration 2 is unreported.

Concentration 3, roughly adjacent to and southeast of Concentration 2, is a historic refuse deposit that measures approximately 5 meters from north to south and 5 meters from east to west. The concentration includes glass, ceramic, and metal assemblages, and automobile parts. The glass assemblage includes one fragment of frosted glass of unreported color. The ceramic assemblage includes what is reported to be two glazed porcelain tile fragments and one earthenware fragment. The metal assemblage is one wire fan cover, one crown cap, and three wire nails. The balance of the reported portion of the concentration is reported as miscellaneous car parts. The further character of the artifacts in Concentration 3 is unreported.

The archaeologists for the applicant interpret the historic component of Site 3 to reflect three dumping events in the early-to-mid-twentieth century. They cite the apparent similar method of refuse disposal among the three concentrations and the relative similarity of the artifacts in the concentrations as evidence that the same individual or group of people are likely to have been responsible for the deposits and that the deposits may originate from a single source. The archaeologists recommend that Site 3, be found ineligible for listing in the CRHR, primarily due to the difficulty in associating the deposit with important historic themes or persons.

The archaeologists did conduct additional archival research for the evaluation program. The study of five USGS maps for the area that date 1915, 1923, 1943, 1947, and 1956 found no structures along the improved dirt road that now fronts the site or within one mile of the site. While the resolution of the documentation for the deposits makes it difficult to assess the actual date ranges that they represent and to thereby more narrowly focus the potential association of the deposits with important historic themes or persons, staff nonetheless recommends that the historic component of Site 3 is not eligible for listing in the CRHR, because it is highly improbable that the deposit, which appears, on the basis of the above information and a field inspection of the site by staff, to be a Depression-era assemblage, would ever be able to yield information important to the early twentieth-century history of the western Mojave Desert.

The archaeologists for the applicant do not explicitly address the whether the prehistoric component of Site 3 is eligible for listing in the CRHR. Staff presently abstains from recommending whether Site 3 is eligible for listing in the CRHR until the preliminary results of the geoarchaeology study are available. Absent a better understanding of the landscape context for the archaeological site and absent any examination of the sedimentary deposits beneath the surface artifact assemblage, staff believes a determination of the historical significance of the site would be premature.

Site 6

Site 6 is an archaeological deposit that includes both prehistoric and historic components. The deposit is approximately one mile to the west of the project site and 650 feet west of SR 14. Both the prehistoric and historic components appear to be surface phenomena. The overall deposit measures approximately 63 meters from northwest to southeast and 40 meters from northeast to southwest. The present site surface appears to be on a mid-slope of the Pine Tree Canyon alluvial fan. The predominant vegetation type on the site appears to be Mojave creosote bush scrub.

The prehistoric component of the deposit is an extremely sparse (~1 piece/229 square meters) scatter of 11 artifacts, which are reported as 1 projectile point base fragment, 3 cores, and 7 stone flakes. The archaeologists for the applicant report that most of the pieces are of CCS. The further character of the artifacts is unreported.

The historic component of Site 6 includes glass, ceramic, tin can, wood, and metal assemblages. The glass assemblage includes an unclear number of fragments of aqua glass, one of which appears to be embossed with the date “March 4, 1924” (Delaware Punch bottle patent date). The ceramic assemblage is reported as 12 glazed, tan (yellowware) fragments, and an unspecified number of white whole plate and white plate fragments, one fragment of which represents a rice bowl. The archaeologists for the applicant identify an unclear number of the white ceramics as being Japanese in origin. The tin can assemblage includes one tobacco tin, and the archaeologists also report one Bully Beef can. The wood assemblage is milled lumber of unreported quantity, dimensions, or finish. The metal assemblage is reported as two nails, one screw, one square bolt, wire, and one oil drum. The further character of the artifacts of Site 6 is unreported.

The archaeologists for the applicant make the assertion in the inventory report (Apple and Glenny 2008, p. 36) that the historic component of Site 6 has the potential, upon the establishment of associations between the component and a particular historic event or theme, through additional archival research or data collection, to yield information important to an unspecified period in the history of the western Mojave Desert and is, therefore, potentially eligible for listing in the CRHR under Criterion 4. While the resolution of the documentation for the deposit makes it difficult to assess the actual date range that it represents and to thereby more narrowly focus the potential association of the deposit with important historic themes or persons, staff nonetheless recommends that the historic component of Site 6 is not eligible for listing in the CRHR, because it is highly improbable that the apparently sparse deposit, which appears, on the basis of the above information, to be a 1920s to 1940s assemblage, would ever be able to yield information important to the early to mid-twentieth century history of the western Mojave Desert.

The archaeologists for the applicant express the opinion that the prehistoric component of Site 6 has the potential to yield information important to prehistoric settlement and lithic technology in the western Mojave Desert and is, therefore, potentially eligible for listing in the CRHR under Criterion 4. The archaeologists cite the diversity of the lithic assemblage as evidence that the use of the site may not have been only for lithic reduction, or tool making. They note that an investigation to discern the presence of a subsurface component at the site would help address the potential historical significance of the site. Staff therefore awaits the results of the geoarchaeology study before recommending whether Site 6 is eligible for listing in the CRHR. Absent a better understanding of the landscape context for the archaeological site and absent any examination of the sedimentary deposits beneath the surface artifact assemblage, staff believes a determination of the historical significance of the site would be premature.

Built Environment Resources Evaluations

There presently appear to be 16 built-environment resources that the proposed project may impact. The resources include 15 standing structures and one historic railroad in the project area of analysis that have the potential to be subject to direct impacts.

Descriptions and evaluations of the historical significance of the 16 built-environment resources that the proposed project may impact are presented below. The information for the descriptions and evaluations is drawn from (Hirsch 2008 and attachment 3 (DPR 523 series forms)).

In their survey, the applicant identified 15 standing structures that were (or would be by 2010) of sufficient age to be considered potentially significant historical resources (Hirsch 2008, p. 20). Fourteen of these resources (21000-21001 and 21257 79th Street, and 21001-21225 Neuralia Road) are simple ranch-style residences constructed between 1963 and1964. These one-story residences are similar in plan and appearance. They are L-shaped buildings with predominantly gable roofs. The exteriors are clad with a combination of stucco and wood-veneer siding, and fenestration consists of aluminum sliding windows.

These 14 ranch-style residences located along 79th Street and along Neuralia are not eligible for inclusion in the CRHR. Evaluated under Criterion 1, the buildings are not associated with events that have made a significant contribution to the broad patterns of our history, either individually or as a part of a larger district. Rather they represent a common trend within the context of residential development. Research did not indicate these residences were associated with historically significant persons, and so they do not appear to be eligible under Criterion 2. Under Criterion 3, these fourteen resources do not embody a distinctive type, period, or method of construction. Instead, they represent a fairly standardized housing type and construction method. These resources are also not eligible under Criterion 4 because they are not likely to yield information important to history.

The remaining potential historical resource, “Rancho Cantil,” located at 7696 Neuralia Road, consists of multiple structures—an abandoned vernacular residential building, a contemporary ranch-style residence, and several outbuildings. The applicant did not have access to the complex and was only able to survey the resource from the public-right of-way. The abandoned residential structure appeared to be the only building that was more than 45 years old. The applicant reviewed historic maps and determined that the resource appears on a 1947 USGS map, and so was constructed prior to 1947. The vernacular residence is a frame structure with a gable roof and appears to have been a ranch house at one time. The contemporary ranch-style house is thought to date within the last 30 years. The outbuildings are thought to be of wood, but neither the exact construction materials nor the age could be determined due to inaccessibility.

The applicant recommended that the pre-1947 vernacular residence at 7696 Neuralia Road could potentially be eligible for inclusion in the CRHR. However, staff believes it does not appear to meet the criteria for inclusion in the CRHR. Agricultural and ranching industries were unsustainable in the Fremont Valley and did not contribute to significant patterns within the development of this region and state. As a result, this residence does not appear to be significant within the patterns of area history under Criterion 1. Research did not indicate this residence was associated with historically significant persons, and so it does not appear to be eligible under Criterion 2. Under Criterion 3, this residence does not embody a distinctive type, period, or method of construction. This residence also is not eligible under Criterion 4 because it is not likely to yield information important to history.

An approximately 1.2-mile stretch of the "Jawbone" Branch (CA-KER-3366H) of the Southern Pacific Railroad forms the western boundary of the proposed BSEP plant site, and so was identified as a built-environment resource in the applicant's survey of the 200-foot buffer zone around project components. This branch extends 90 miles from Mojave through the Jawbone region and Owens Valley to Owenyo (a few miles north of Lone Pine). The line was built between 1908 and 1912 to carry supplies for the construction of the Los Angeles Aqueduct. The first 23 miles of the branch line opened to Cantil on June 1, 1905. The applicant states that the Jawbone Branch is potentially significant under CRHR Criterion 1 for its association with the construction of the Los Angeles Aqueduct (BS 2008a).

Railroads, with their associated tunnels, trestles, and bridges are potentially significant under Criterion 1 if they are significantly associated with trends and/or events in transportation development or regional or local economic development. Railroads, however, like other transportation infrastructure, are inherently important to their communities, as they affect communication and the distribution of people, goods, and services that in turn affects development on both the local and regional levels. This effect is not typically sufficient to warrant recognition of a railroad as significant under Criterion 1, otherwise virtually any railroad, with its associated structures, would be shown to be important in this way.

To be eligible for listing in the CRHR, resource types such as railroads and other transportation infrastructure must have demonstrable importance directly related to important historic events and trends, with emphasis given to specific demand for such infrastructure, and its effects on social, economic, commercial, and industrial developments locally, regionally, or nationally. In this way, railroad lines and associated structures, may be significant as physical manifestations of important transportation and community developments on the local, regional, state, or national level.

The most common instance in which a railroad line or its separate structural components might be considered under Criterion 1 would be if either the line or separate components (tunnels, trestles, or bridges) were the first to be located at its site, thus providing expanded transportation opportunity and advancing economic development into previously isolated or underdeveloped areas. This development trend is identified as “ahead of demand” development, indicating the transportation route predated development and subsequent development directly related to the presence of the transportation route. One such example of this development pattern would be the line the Southern Pacific Railroad constructed down the length of California’s San Joaquin Valley. While several towns connected by wagon roads existed in the Central Valley prior to the coming of the railroad, the placement of the new line away from the wagon road initiated the development of a large number of new towns along the new transportation route. These towns, now the location of the valley’s main populations, exist because the railroad was built through a previously undeveloped area, which in turn opened a new area for economic development.

In the case of the Jawbone Branch, the line did not significantly affect trends and or events in the development within the regional or local economy. Railroads are not likely to be eligible under Criterion 2 because they rarely illustrate a person’s important achievements under Criterion 2. Historically significant persons associated with the development of the Southern Pacific Railroad are better represented by other historical resources. Under Criterion 3, this segment of the railroad does not represent embody a distinctive type, period, or method of construction nor would this resource be eligible under Criterion 4, for its potential to yield important information because railroads are well documented in the historical record.

Summary of CRHR-Eligible Resources for the Beacon Solar Energy Project

There are presently five cultural resources in the proposed project area that staff recommends as eligible for listing on the CRHR and that are, consequently, historical resources for the purposes of CEQA. The five historical resources are Sites 8, 9, and 11–13.

There are nine further cultural resources in the proposed project area that staff recommends assuming as eligible for listing in the CRHR for the purpose of the present staff assessment. Each of the nine resources, by benefit of the above assumption, would be historical resources under CEQA, and the consideration of the potential impacts of the proposed project on each would continue to be a part of the present analysis until such time as staff is able to recommend, on the basis of the results of the geoarchaeology study or further research, that a particular resource is not eligible for such listing. The nine resources are Sites 3, 6, 16–19, 54, 59, and BSPL-H-2. Staff recommendations on the historical significance of five of the nine subject resources, Sites 3, 6, and, 17–19, await the results of the geoarchaeology study (see “Geoarchaeology Study” subsection, above) for a better understanding of the landscape context for each of these archaeological sites. Staff presently abstains from making historical significance recommendations in the present preliminary assessment for the four remaining sites, Sites 16, 54, 59 and BSPL-H-2, pending further consultation with the applicant on, variably, the character of site artifact assemblages and the rationale that structures arguments of historical significance.

The potential impacts of the proposed project on Sites 8, 9, and 11–13, fire-affected rock deposits that often include intact, buried fire features, and the outline of a program to mitigate those impacts and similar impacts to other archaeological sites of the same type that appear to be distributed in a zone across the eastern and northern portions of the project site are developed below.

The consideration of the potential impacts to Sites 3, 6, 16–19, 54, 59, and BSPL-H-2 and the mitigation for those impacts is being deferred to the FSA to allow staff and the applicant the opportunity to verify which of the sites may be subject to avoidance, to analyze the results of the geoarchaeology study, and to conclude consultation on the character of particular site artifact assemblages and the rationale that structures several of the applicant's arguments of historical significance, where such issues are unclear.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE OF IMPACTS TO HISTORICAL RESOURCES

Under CEQA, "a project that may cause a substantial adverse change in the significance of an historical resource is a project that may have a significant effect on the environment" (Pub. Resources Code, § 21084.1). Thus, staff analyzes whether a proposed project would cause a substantial adverse change in the significance, that is, the CRHR eligibility, of all historical resources identified in the Cultural Resources Inventory as CRHR eligible. The degree of significance of an impact depends on:

- The cultural resource impacted;
- The nature of the resource's historical significance;
- How the resource's historical significance is manifested physically and perceptually;
- Appraisals of those aspects of the resource's integrity that figure importantly in the manifestation of the resource's historical significance; and
- How much the impact will change those integrity appraisals.

DIRECT/INDIRECT IMPACTS AND MITIGATION

In the abstract, direct impacts to cultural resources are those associated with project development, construction, and co-existence. Construction usually entails surface and subsurface disturbance of the ground, and direct impacts to archaeological resources may result from the immediate disturbance of the deposits, whether from vegetation removal, vehicle travel over the surface, earth-moving activities, excavation, or demolition of overlying structures. Construction can have direct impacts on historic standing structures when those structures must be removed to make way for new structures or when the vibrations of construction impair the stability of historic structures nearby. New structures can have direct impacts on historic structures when the new structures are stylistically incompatible with their neighbors and the setting, and when the new structures produce something harmful to the materials or structural integrity of the historic structures, such as emissions or vibrations.

Generally speaking, indirect impacts to archaeological resources are those which may result from increased erosion due to site clearance and preparation, or from inadvertent damage or outright vandalism to exposed resource components due to improved accessibility. Similarly, historic structures can suffer indirect impacts when project construction creates improved accessibility and vandalism or greater weather exposure becomes possible.

Ground disturbance accompanying construction at a proposed plant site, along proposed linear facilities, and at a proposed laydown area has the potential to directly impact archaeological resources, unidentified at this time. The potential direct, physical impacts of the proposed construction on unknown archaeological resources are commensurate with the extent of ground disturbance entailed in the particular mode of construction. This varies with each component of the proposed project. Placing the proposed plant into this particular setting could have a direct impact on the integrity of association, setting, and feeling of nearby standing historic structures.

Construction Impacts and Mitigation

Identification and Assessment of Direct Impacts on Archaeological Resources and Proposed Mitigation

The assessment of the potential direct impacts of the proposed project on archaeological resources is presented below relative to three primary project components, the main plant site or project site, the transmission line, and the natural gas pipeline. Conceptual outlines of mitigation proposals for the impacts of each project component conclude the assessment for each respective component.

Main Plant Site

Construction related activities on the main plant site, or project site, have the potential to cause significant impacts to archaeological resources as follows:

- During site preparation, grading and leveling would take place (BS 2008a, p. 2-26), with a cut and fill method employed. These activities would destroy all surface archaeological resources on the project site and may potentially impact buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.
- During construction, a 14,000-foot long drainage channel would be constructed, with an average channel depth of 8 feet (BS 2008a, p. 2-25). This excavation could potentially impact buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.
- During construction, a 9,000-foot long existing railroad drainage (1 foot deep and minimally 15 feet wide at the bottom) would be rerouted towards the rerouted dry wash (BS 2008a, p. 2-25). These activities could potentially impact buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.
- During construction, three evaporation ponds measuring 8.3 acres each, with a depth not yet determined, would be excavated (BS 2008a, p. 2-19). These

excavations could potentially impact buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.

- During construction, security fencing would be installed surrounding the project site, including the solar field (BS 2008a, p. 2-25). This activity could potentially impact buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.
- During construction, in the event that new water supply wells would be installed (BS 2008a, p. 2-14), these excavations could potentially impact buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.
- During construction, holes for foundations for components would be excavated (BS 2008a, p. 2-4–2-5; DB 2008d, Response to Data Request No. 33). These excavations could potentially impact buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.

CULTURAL RESOURCES TABLE 7
Summary of Project Components and Component Foundation Depths

Project Component	Foundation Depth[16]
Steam Turbine	8'–10'
Circulating Water Pipe	12'–15'
Cooling Tower Basin	18'–22'
Oil/Water Separator	2.5'–3' (above ground)
Solar Field Pedestals	12'–15'

* DB 2008d, Response to Data Request No. 33

The primary significant direct impact of the construction of the proposed project on historical resources on the project site presently appears to be the complete destruction of Sites 8, 9, and 11–13. It also appears likely, at present, that other archaeological sites similar in character to the subject sites are buried in a zone (Archaeological Zone 1) across the eastern and northern portions of the project site. Many of these latter potential archaeological deposits would also be subject to destruction as a result of the proposed construction activity. The results of the geoarchaeology study will provide a factual basis to help delimit the extent of Archaeological Zone 1 and to estimate the potential population of the above and other types of buried archaeological deposits in the zone.

Staff will propose in the FSA, as a condition of certification, a mitigation program for Archaeological Zone 1, the purpose of which will be to reduce the direct impacts of construction activity on the historical resources in the zone to less than significant. The results of the geoarchaeology study (see "Geoarchaeology Study" subsection, above)

[16] Once the fill has been placed, the elevations of the components inside of the power block would be 0'–5' less than what is shown here.

and further consultation with the applicant are requisite antecedents to the preparation of the formal program. Staff takes the opportunity here to propose the broad strokes of the mitigation program to stimulate public discussion on its potential form.

The basic staff proposal for the mitigation program for Archaeological Zone 1 is for a phased program that mitigates the impact of the proposed project on a particular archaeological site type, clusters of prehistoric fire features. Staff envisions phases to better inventory the population of fire features in the zone, to document the variation in the physical character, the content, and the age of the features, and to document the material culture assemblages that may be present on the buried land surfaces that may surround the features.

There a number of options to consider to better inventory the buried prehistoric fire features that are likely to be present in Archaeological Zone 1. A staff field inspection on January 27, 2009, of the subsurface stratigraphy of the zone during the field phase of the geoarchaeology study found that the sedimentary deposits below the surface of the zone are largely made up of fine-grained silts that contain almost no gravel. The types of fire features that are now known from Sites 8, 9, 11, and 12, features that typically include clusters of fire-affected, igneous pebbles and cobbles, and fire-hardened bands of oxidized sediments, are so distinct from the sedimentary matrix that encases them that the features may be high quality candidates for location using geophysical methods such as ground-penetrating radar or magnetometry. The use of geophysical methods to conduct a sample survey as the initial inventory phase of the mitigation program offers the opportunity to more accurately and efficiently document the extent and the character of Archaeological Zone 1. The results of a geophysical survey would be subject to ground-truthing to verify and refine the survey results. If the results of the geophysical survey prove to be reliable, then the mitigation program would shift into a data recovery phase to investigate a sample of the fire features and to search for and document a sample of the buried land surfaces that may surround them. If the results of the geophysical survey prove inconclusive, then a sample subsurface survey of the zone would be conducted mechanically using equipment such as a road grader.

Staff envisions a data recovery phase for the Archaeological Zone 1 mitigation program that would include two primary investigative foci. One focus would be small excavation exposures to uncover and document a sample of the fire features in the zone. The purpose of this documentation would be to gather data for the description of the physical variability of the features in the archaeological record, for the identification and inventory of the artifacts and ecofacts that are found in them, and for the interpretation of the methods of construction and the potential uses of the features. A second focus would be larger block exposures to attempt to uncover a sample of the buried land surfaces that may surround the fire features and to document the material culture assemblages that may be found on such surfaces. The purpose of this documentation would be to gather data on the composition and spatial distribution of the assemblages for more holistic interpretations of the use of the features and for interpretations of the broader behavioral contexts in which the use of the features were embedded. A staff field inspection on January 27, 2009, of the subsurface stratigraphy of the zone during the field phase of the geoarchaeology study found that the preservation of subtle sedimentary features such as ancient polygonal surface cracks was common and indicates that the character of the sedimentary deposition in Archaeological Zone 1 would highly favor the preservation of archaeological deposits.

The construction of the proposed project may pose other significant impacts on historical resources on the project site. It is not presently well understood the extent to which known surface archaeological sites may have significant subsurface components. There may also be other buried archaeological sites outside of Archaeological Zone 1, or buried archaeological sites of other types may be in Archaeological Zone 1.

The results of the geoarchaeology study will provide a factual basis to help develop, in the FSA, the scope of the construction monitoring that will be necessary on the project site. Staff will propose a condition of certification for construction monitoring that prescribes different monitoring protocols for the project site, the transmission line alignment, and the natural gas pipeline alignment. The protocol for the project site will incorporate the results of the geoarchaeology study to tailor, and hopefully, diminish, the necessary scope for that monitoring effort.

Transmission Line

Construction-related activities have the potential to cause significant impacts to archaeological resources in or near the two proposed alternative project transmission line routes as follows:

- Foundation holes for 36 new steel/concrete monopoles (the same number would be required for either alternate route) would be excavated along the selected transmission line route (BS 2008a, p. 2-30). These activities could potentially impact surface archaeological resources in or near the selected transmission line route, and buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.
- A new dirt access road to the LADWP Inyo-Barren Ridge 230-kV transmission line would be cleared and graded, the length of the new road—1.0 mile or 1.9 miles—depending on which transmission line option is selected. Additionally, new stub access roads, about 100 feet long, would be cleared and graded from the existing LADWP service road to each of the Inyo-Barren Ridge 230-kV transmission line towers (BS 2008a, p. 2-30). These activities could potentially impact surface archaeological resources along these new roads, and buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.
- Eight pulling sites would be established along the selected transmission line route (BS 2008a, p. 2-32). The pulling activities could potentially impact surface archaeological resources in or near the selected transmission line route, and buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.

No significant direct construction impacts to historical resources along the alignment for the proposed transmission line are presently confirmed (see “Summary of CRHR-Eligible Resources for the Beacon Solar Energy Project” subsection, above). There appear to be two archaeological sites, Sites 54 and 59 (see “Archaeological Resources” subsection, above), that would potentially be subject to construction impacts from the proposed project, but the status of the sites as being eligible for listing on the CRHR or as being chosen by the applicant for avoidance remains unresolved at this time. Staff will propose any plans for the disposition of the sites that are ultimately requisite as conditions of certification in the FSA. The condition of certification that covers construction monitoring will include a monitoring protocol appropriate to the character of the construction impacts along the transmission line alignment.

Natural Gas Pipeline

Construction-related activities have the potential to cause significant impacts to archaeological resources in or near the natural gas pipeline corridor as follows:

- During construction, a 48-inch-wide trench for the installation of a new 17.6-mile long, 8-inch-diameter natural gas pipeline would be excavated to a depth of 4 to 10 feet below the surface to connect the proposed power plant to an existing Southern California Gas (SCG) pipeline located west of California City (BS 2008a, p. 2-27–28). These excavations could potentially impact buried archaeological resources, unidentified at this time, to the extent of the area and depth of the ground disturbance in the native soils of the site.

No significant direct construction impacts to historical resources along the alignment for the proposed natural gas pipeline are presently confirmed (see “Summary of CRHR-Eligible Resources for the Beacon Solar Energy Project” subsection, above). There appears to be one archaeological site, BSPL-H-02 (see “Archaeological Resources” subsection, above), that would potentially be subject to construction impacts from the proposed project, but the status of the site as being eligible for listing on the CRHR or as being chosen by the applicant for avoidance remains unresolved at this time. Staff will propose any plan for the disposition of the site that is ultimately requisite as a condition of certification in the FSA. The condition of certification that covers construction monitoring will include a monitoring protocol appropriate to the character of the construction impacts along the natural gas pipeline alignment.

Identification and Assessment of Direct Impacts on Ethnographic Resources

No ethnographic resources, either previously recorded or newly disclosed in the communications with Native Americans conducted by the applicant for the proposed project, were identified in the vicinity of the project. The proposed project would, therefore, have no significant impact on ethnographic resources.

Identification and Assessment of Direct Impacts on Built-Environment Resources and Proposed Mitigation

No built-environment resources that qualify as historical resources for the purpose of CEQA analysis are now known or likely to be found in the project area of analysis. The proposed project would, therefore, have no significant impact on built-environment resources.

Indirect Impacts

Neither the applicant nor Energy Commission staff has identified any indirect impacts to any CRHR-eligible resources in the project area of analysis. Staff believes, therefore, that mitigation for indirect impacts is not necessary for the proposed project.

Operation Impacts and Mitigation

During operation of the proposed BSEP project, if a leak should develop in the gas or water pipelines supplying the plant, repair of the buried utility could require the excavation of a large hole. Such repairs could impact previously unknown subsurface archaeological resources in areas unaffected by the original excavation. The measures proposed above and below to mitigate impacts to previously unknown archaeological resources found during the construction of the proposed project would also serve to mitigate impacts that occur due to repairs that are made during the operation of the plant.

Cumulative Impacts and Mitigation

A cumulative impact refers to a proposed project's incremental effects considered over time and together with those of other, nearby, past, present, and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project (Pub. Resources Code sec. 21083; Cal. Code Regs., tit. 14, secs. 15064(h), 15065(a)(3), 15130, and 15355). Cumulative impacts to cultural resources in the BSEP vicinity could occur if any other existing or proposed projects, in conjunction with the proposed BSEP, had or would have impacts on cultural resources that, considered together, would be significant. The previous ground disturbance from prior projects and the ground disturbance related to the future construction of the BSEP and other proposed projects in the vicinity could have a cumulatively considerable effect on subsurface archaeological deposits, both prehistoric and historic. The alteration of the setting which could be caused by the construction and operation of the proposed BSEP and other proposed projects in the vicinity could be cumulatively considerable, but may or may not be a significant impact to cultural resources.

In addition to the BSEP, the applicant has identified two other projects in the general area. The Los Angeles Department of Water and Power (LADWP) Barren Ridge-Castaic Transmission Project is a transmission line which would run south from the Barren Ridge Switching Station (located about 1.5 miles south of the project site and the point of interconnection for BSEP’s Option 1 transmission line) to Los Angeles County. This LADWP project is in the early stages of the environmental review process, and no data on potential cultural resources impacts are yet available (BS2008a, p. 5.4-24). Consequently, this project’s contribution to a cumulative impact to cultural resources has not yet been determined.

Cultural resources consultants for the other known nearby project, the Pine Tree Wind Development project (located six miles west of the BSEP site) identified seven archaeological sites recommended as CRHR eligible and requiring impact mitigation in the form of data recovery (BS 2008a, p. 5.4-24). Thus this project’s impacts would be mitigated, and it would not contribute to a cumulative impact to cultural resources. Staff is not aware of any other projects in the vicinity of the BSEP site.

Staff has proposed conditions of certification that would mitigate the BSEP's impacts to known CRHR-eligible cultural resources to below the level of significance. Staff has also proposed conditions of certification for the BSEP project providing for identification, evaluation, and avoidance or mitigation of impacts to previously unknown CRHR-eligible archaeological resources discovered during the construction of the project.

Proponents of any other future projects in the vicinity of the BSEP could mitigate impacts to as-yet-undiscovered subsurface archaeological sites to less-than-significant levels by requiring construction monitoring, evaluation of resources discovered during monitoring, and avoidance or data recovery for resources evaluated as CRHR-eligible. Impacts to human remains can be mitigated by following the protocols established by state law in Public Resources Code, section 5097.98. Since the impacts from the proposed BSEP would be mitigated to a less-than-significant level by the project's compliance with proposed Conditions of Certification **CUL-1** through **CUL-8**, and since similar protocols can be applied to other projects in the area, staff does not expect any incremental effects on cultural resources of the proposed BSEP to be cumulatively considerable when viewed in conjunction with other projects.

COMPLIANCE WITH LORS

If the conditions of certification below and those that Energy Commission staff will propose in the FSA are properly implemented, the proposed BSEP would result in a less-than-significant impact on known and newly found cultural resources. The project would therefore be in compliance with the applicable state laws, ordinances, regulations, and standards listed in Table 1.

Kern County's General Plan has language promoting the general county-wide preservation of cultural resources, CEQA compliance for discretionary projects, and notification of Native Americans about discretionary projects of concern to them. Staff's proposed conditions of certification here and those that staff will propose in the FSA will require specific actions not just to promote but to effect historic preservation and mitigate impacts to all cultural resources in order to ensure CEQA compliance. Consequently, if BSEP implements these conditions, its actions would be consistent with the cultural-resources-related goals of Kern County.

CONCLUSIONS AND RECOMMENDATIONS

The present cultural resources analysis is able to conclude that the construction, operation, and maintenance of the BSEP will cause substantial adverse changes in the significance of historical resources, but staff is presently unable to identify or adequately anticipate the complete scope of these significant effects to the environment. The conditions of certification proposed here are, consequently, incomplete.

The applicant is in the process of preparing a geoarchaeology study (see "Geoarchaeology Study" subsection, above) the results of which will provide relatively high resolution information critical to a substantive analysis of the scope of the impacts that the project would have on cultural resources and to the development of effective mitigation measures that may demonstrably reduce such impacts to less than significant. At present, absence of the results of the geoarchaeology study precludes the ability of staff to make recommendations to the Energy Commission on the eligibility of a number of archaeological sites and archaeological site components in the project area (prehistoric components of Sites 3 and 6, and Sites 17–19) for listing in the CRHR (see “Archaeological Resources” subsection, above). The results of the geoarchaeology study are also critical to the preparation of the proposed mitigation program for Archaeological Zone 1 across the northern and eastern portions of the project site (see “Archaeological Resources in the Project Area” subsection, above). Archaeological Zone 1 is a zone of clusters of surface and subsurface prehistoric fire features the extent and character of which are as yet poorly known. The zone includes five historical resources (Sites 8, 9, and 11–13) which may be destroyed as result of project construction. Energy Commission staff envisions a condition of certification for a proposed, multiple-phase program of mitigation to better inventory the population of the fire features in the zone, to recover data on the variation in the physical character, the content, and the age of the features, and to recover data on the material culture assemblages that may be present on the buried land surfaces that may surround the features. The applicant is presently in the process of conducting the geoarchaeology study and foresees being able to provide preliminary results of the study prior to the publication of the FSA.

The construction, operation, and maintenance of the proposed project also has the potential to have significant impacts on four additional archaeological sites (Sites 16, 54, 59 and BSPL-H-2) the historical significance of which remain uncertain (see “Archaeological Resources” subsection, above). Staff anticipates that further consultation with the applicant on such issues as the character of the artifact assemblages on some of the sites and the rationale that structures arguments of the historical significance of others will resolve the outstanding concerns and facilitate the final disposition of these cultural resources. Should any of these archaeological sites warrant staff recommendations as being historical resources, staff would propose conditions of certification in the FSA to mitigate the potential impacts of the proposed project on them.

A final consideration that will shape the need for and the character of the conditions of certification that staff will propose for the FSA is that the applicant has informally proposed to avoid a total of five archaeological sites (Sites 6, 8, 54, BSPL-H-2, and CA-KER-3366H). The archaeologists for the applicant relate in the report of the evaluation program (Apple, Cleland, and Glenny 2008, p. v) that the applicant had committed to avoiding Sites 6, 54, BSPL-H-2, and CA-KER-3366H prior to the implementation of the evaluation program and subsequently committed to avoiding Site 8. Staff is unaware of any formal public commitments to avoid these cultural resources and does not know whether the applicant would propose to avoid the resources through the re-design of portions of the proposed project or through the implementation of avoidance measures. Staff requests that the applicant clarify, in response to the present document, whether and how the proposed project intends to avoid the above archaeological sites. Any plans to avoid the archaeological sites through the implementation of avoidance measures would require conditions of certification to facilitate such avoidance. Any plans to avoid the archaeological sites through project re-design would not.

The proposed conditions of certification below, **CUL-1** through **CUL-8**, are standard cultural resources conditions that are applicable to the proposed project. The conditions are intended to facilitate the identification and assessment of previously unknown archaeological resources encountered during construction-related ground disturbance and to mitigate any significant impacts from the project on any newly found resources assessed as CRHR-eligible. To accomplish this, the conditions provide for the hiring of a Cultural Resources Specialist and archaeological monitors, for cultural resources awareness training for construction workers, for the archaeological and Native American monitoring of ground-disturbing activities, in particular situations, for the recovery of data from CRHR-eligible discovered archaeological deposits, for the writing of a technical archaeological report on all archaeological activities and findings, and for the curation of recovered artifacts and other data. When properly implemented and enforced, staff believes that these conditions of certification would contribute toward reducing to less-than-significant any impacts to previously unknown cultural resources encountered during construction or operation. The adoption and implementation of these conditions would also foster BSEP conformity with applicable LORS.

Staff anticipates modifying the proposed conditions of certification prior to the publication of the FSA in response to the results of the geoarchaeology study and further consultation with the applicant. The FSA will also include conditions of certification for the mitigation program for Archaeological Zone 1, and for the mitigation or protection of other archaeological sites that are ultimately recommended as being eligible for listing in the CRHR.

PROPOSED CONDITIONS OF CERTIFICATION

CUL-1 Prior to the start of ground disturbance (includes “preconstruction site mobilization,” “construction ground disturbance,” and “construction grading, boring and trenching,” as defined in the General Conditions for this project) the project owner shall obtain the services of a Cultural Resources Specialist (CRS), and one or more alternate CRSs, if alternates are needed. The CRS shall manage all monitoring, mitigation, curation, and reporting activities required in accordance with the Conditions of Certification (Conditions). The CRS may elect to obtain the services of Cultural Resources Monitors (CRMs) and other technical specialists, if needed, to assist in monitoring, mitigation, and curation activities. The project owner shall ensure that the CRS makes recommendations regarding the eligibility for listing in the California Register of Historical Resources (CRHR) of any cultural resources that are newly discovered or that may be affected in an unanticipated manner. No ground disturbance shall occur prior to CPM approval of the CRS and alternates, unless such activities are specifically approved by the CPM. Approval of a CRS may be denied or revoked for non-compliance on this or other projects.

CULTURAL RESOURCES SPECIALIST

The resumes for the CRS and alternate(s) shall include information demonstrating to the satisfaction of the CPM that their training and backgrounds conform to the U.S. Secretary of Interior's Professional Qualifications Standards, as published in Title 36, Code of Federal Regulations, part 61 (36 C.F.R., part 61). In addition, the CRS shall have the following qualifications:

1. The CRS's qualifications shall be appropriate to the needs of the project and shall include a background in anthropology, archaeology, history, architectural history, or a related field;

2. At least three years of archaeological or historical, as appropriate (per nature of predominant cultural resources on the project site), resource mitigation and field experience in California; and

3. At least one year of experience in a decision-making capacity on cultural resources projects in California and the appropriate training and experience to knowledgably make recommendations regarding the significance of cultural resources.

The resumes of the CRS and alternate CRS shall include the names and telephone numbers of contacts familiar with the work of the CRS/alternate CRS on referenced projects and demonstrate to the satisfaction of the CPM that the CRS/alternate CRS has the appropriate training and experience to implement effectively the Conditions.

CULTURAL RESOURCES MONITORS

CRMs shall have the following qualifications:

1. a B.S. or B.A. degree in anthropology, archaeology, historical archaeology or a related field and one year experience monitoring in California; or

2. an A.S. or A.A. degree in anthropology, archaeology, historical archaeology or a related field, and four years experience monitoring in California; or

3. enrollment in upper division classes pursuing a degree in the fields of anthropology, archaeology, historical archaeology or a related field, and two years of monitoring experience in California.

CULTURAL RESOURCES TECHNICAL SPECIALISTS

The resume(s) of any additional technical specialist(s), e.g., historical archaeologist, historian, architectural historian, and/or physical anthropologist, shall be submitted to the CPM for approval.

Verification

1. At least 45 days prior to the start of ground disturbance, the project owner shall submit the resume for the CRS, and alternate(s) if desired, to the CPM for review and approval.

2. At least 10 days prior to a termination or release of the CRS, or within 10 days after the resignation of a CRS, the project owner shall submit the resume of the proposed new CRS to the CPM for review and approval. At the same time, the project owner shall also provide to the proposed new CRS the AFC and all cultural resources documents, field notes, photographs, and other cultural resources materials generated by the project. If

there is no alternate CRS in place to conduct the duties of the CRS, a previously approved monitor may serve in place of a CRS so that project-related ground disturbance may continue up to a maximum of 3 days without a CRS. If cultural resources are discovered then ground disturbance will remain halted until there is a CRS or alternate CRS to make a recommendation regarding significance.

3. At least 20 days prior to ground disturbance, the CRS shall provide a letter naming anticipated CRMs for the project and stating that the identified CRMs meet the minimum qualifications for cultural resources monitoring required by this Condition. If additional CRMs are obtained during the project, the CRS shall provide additional letters to the CPM identifying the CRMs and attesting to the qualifications of the CRMs, at least 5 days prior to the CRMs beginning on-site duties.

4. At least 10 days prior to any technical specialists beginning tasks, the resume(s) of the specialists shall be provided to the CPM for review and approval.

5. At least 10 days prior to the start of ground disturbance, the project owner shall confirm in writing to the CPM that the approved CRS will be available for onsite work and is prepared to implement the cultural resources conditions.

CUL-2 Prior to the start of ground disturbance, if the CRS has not previously worked on the project, the project owner shall provide the CRS with copies of the AFC, data responses, and confidential cultural resources reports for the project. The project owner shall also provide the CRS and the CPM with maps and drawings showing the footprints of the power plant, all linear facility routes, all access roads, and all laydown areas. Maps shall include the appropriate USGS quadrangles and a map at an appropriate scale (e.g., 1:2000 or 1" = 200') for plotting cultural features or materials. If the CRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the CRS and CPM. The CPM shall review map submittals and, in consultation with the CRS, approve those that are appropriate for use in cultural resources planning activities. No ground disturbance shall occur prior to CPM approval of maps and drawings, unless such activities are specifically approved by the CPM.

If construction of the project would proceed in phases, maps and drawings not previously provided shall be submitted prior to the start of each phase. Written notification identifying the proposed schedule of each project phase shall be provided to the CRS and CPM.

At a minimum, the CRS shall consult weekly with the project construction manager to confirm area(s) to be worked during the next week, until ground disturbance is completed.

The project owner shall notify the CRS and CPM of any changes to the scheduling of the construction phases.

Verification

1. At least 40 days prior to the start of ground disturbance, the project owner shall provide the AFC, data responses, and confidential cultural resources documents to the CRS, if needed, and the subject maps and drawings to the CRS and CPM. The CPM will review submittals in consultation with the CRS and approve maps and drawings suitable for cultural resources planning activities.

2. If there are changes to any project-related footprint, revised maps and drawings shall be provided at least 15 days prior to start of ground disturbance for those changes.

3. If project construction is phased, if not previously provided, the project owner shall submit the subject maps and drawings 15 days prior to each phase.

4. On a weekly basis during ground disturbance, a current schedule of anticipated project activity shall be provided to the CRS and CPM by letter, e-mail, or fax.

5. Within 5 days of identifying changes, the project owner shall provide written notice of any changes to scheduling of construction phase.

CUL-3 Prior to the start of ground disturbance, the project owner shall submit the Cultural Resources Monitoring and Mitigation Plan (CRMMP), as prepared by or under the direction of the CRS, to the CPM for review and approval. The CRMMP shall follow the content and organization of the model CRMMP, provided by the CPM, and the authors' name(s) shall appear on the title page of the CRMMP. The CRMMP shall identify general and specific measures to minimize potential impacts to sensitive cultural resources. Implementation of the CRMMP shall be the responsibility of the CRS and the project owner. Copies of the CRMMP shall reside with the CRS, alternate CRS, each CRM, and the project owner's on-site construction manager. No ground disturbance shall occur prior to CPM approval of the CRMMP, unless such activities are specifically approved by the CPM.

The CRMMP shall include, but not be limited to, the following elements and measures:

1. The following statement included in the Introduction: "Any discussion, summary, or paraphrasing of the Conditions of Certification in this CRMMP is intended as general guidance and as an aid to the user in understanding the Conditions and their implementation. The conditions, as written in the Commission Decision, shall supersede any summarization, description, or interpretation of the conditions in the CRMMP. The Cultural Resources Conditions of Certification from the Commission Decision are contained in Appendix A."

2. A proposed general research design that includes a discussion of archaeological research questions and testable hypotheses specifically applicable to the project area, and a discussion of artifact collection, retention/disposal, and curation policies as related to the research questions formulated in the research design. The research design will specify that the

preferred treatment strategy for any buried archaeological deposits is avoidance. A mitigation plan shall be prepared for any CRHR-eligible (as determined by the CPM) resource, impacts to which cannot be avoided. A prescriptive treatment plan may be included in the CRMMP for limited data types.

3. Specification of the implementation sequence and the estimated time frames needed to accomplish all project-related tasks during the ground disturbance and post-ground–disturbance analysis phases of the project.

4. Identification of the person(s) expected to perform each of the tasks, their responsibilities, and the reporting relationships between project construction management and the mitigation and monitoring team.

5. A description of the manner in which Native American observers or monitors will be included, the procedures to be used to select them, and their role and responsibilities.

6. A description of all impact-avoidance measures (such as flagging or fencing) to prohibit or otherwise restrict access to sensitive resource areas that are to be avoided during project-related ground disturbance, construction, and/or operation, and identification of areas where these measures are to be implemented. The description shall address how these measures would be implemented prior to the start of ground disturbance and how long they would be needed to protect the resources from project-related effects.

7. A statement that all encountered cultural resources over 50 years old shall be recorded on Department of Parks and Recreation (DPR) 523 forms and mapped and photographed. In addition, all archaeological materials retained as a result of the archaeological investigations (survey, testing, data recovery) shall be curated in accordance with the California State Historical Resources Commission's *Guidelines for the Curation of Archaeological Collections*, into a retrievable storage collection in a public repository or museum.

8. A statement that the project owner will pay all curation fees for artifacts recovered and for related documentation produced during cultural resources investigations conducted for the project. The project owner shall identify three possible curation facilities that could accept cultural resources materials resulting from project activities.

9. A statement that the CRS has access to equipment and supplies necessary for site mapping, photography, and recovery of any cultural resource materials that are encountered during ground disturbance and cannot be treated prescriptively.

10. A description of the contents and format of the final Cultural Resource Report (CRR), which shall be prepared according to ARMR guidelines.

Verification

1. Upon approval of the CRS proposed by the project owner, the CPM will provide to the project owner an electronic copy of the draft model CRMMP for the CRS.

2. At least 30 days prior to the start of ground disturbance, the project owner shall submit the CRMMP to the CPM for review and approval.

3. At least 30 days prior to the start of ground disturbance, a letter shall be provided to the CPM indicating that the project owner agrees to pay curation fees for any materials collected as a result of the archaeological investigations (survey, monitoring, testing, data recovery).

CUL-4 The project owner shall submit the final Cultural Resources Report (CRR) to the CPM for approval. The final CRR shall be written by or under the direction of the CRS and shall be provided in the ARMR format. The final CRR shall report on all field activities including dates, times and locations, findings, samplings, and analyses. All survey reports, DPR 523 forms, data recovery reports, and any additional research reports not previously submitted to the California Historical Resource Information System (CHRIS) and the State Historic Preservation Officer (SHPO) shall be included as appendices to the final CRR.

If the project owner requests a suspension of ground disturbance and/or construction activities, then a draft CRR that covers all cultural resources activities associated with the project shall be prepared by the CRS and submitted to the CPM for review and approval on the same day as the suspension/extension request. The draft CRR shall be retained at the project site in a secure facility until ground disturbance and/or construction resumes or the project is withdrawn. If the project is withdrawn, then a final CRR shall be submitted to the CPM for review and approval at the same time as the withdrawal request.

Verification

1. Within 90 days after completion of ground disturbance (including landscaping), the project owner shall submit the final CRR to the CPM for review and approval. If any reports have previously been sent to the CHRIS, then receipt letters from the CHRIS or other verification of receipt shall be included in an appendix.

2. Within 90 days after completion of ground disturbance (including landscaping), the project owner shall provide to the CPM a copy of an agreement with, or other written commitment from, a curation facility that meets the standards stated in the California State Historical Resources Commission's *Guidelines for the Curation of Archaeological Collections*, to accept cultural materials, if any, from this project. Any agreements concerning curation will be retained and available for audit for the life of the project.

3. Within 10 days after CPM approval, the project owner shall provide documentation to the CPM confirming that copies of the final CRR have been provided to the

SHPO, the CHRIS, the curating institution, if archaeological materials were collected, and to the Tribal Chairpersons of any Native American groups requesting copies of project-related reports.

4. Within 30 days after requesting a suspension of construction activities, the project owner shall submit a draft CRR to the CPM for review and approval.

CUL-5 Prior to and for the duration of ground disturbance, the project owner shall provide Worker Environmental Awareness Program (WEAP) training to all new workers within their first week of employment at the project site, laydown area, and along the linear facilities routes. The training shall be prepared by the CRS, may be conducted by any member of the archaeological team, and may be presented in the form of a video. The CRS shall be available (by telephone or in person) to answer questions posed by employees. The training may be discontinued when ground disturbance is completed or suspended, but must be resumed when ground disturbance, such as landscaping, resumes. The training shall include:

1. A discussion of applicable laws and penalties under the law;
2. Samples or visuals of artifacts that might be found in the project vicinity;
3. A discussion of what such artifacts may look like when partially buried, or wholly buried and then freshly exposed;
4. A discussion of what prehistoric and historical archaeological deposits look like at the surface and when exposed during construction, and the range of variation in the appearance of such deposits;
5. Instruction that the CRS, alternate CRS, and CRMs have the authority to halt project-related ground disturbance in the area of a discovery to an extent sufficient to ensure that the resource is protected from further impacts, as determined by the CRS;
6. Instruction that employees are to halt work on their own in the vicinity of a potential cultural resources discovery and shall contact their supervisor and the CRS or CRM, and that redirection of work would be determined by the construction supervisor and the CRS;
7. An informational brochure that identifies reporting procedures in the event of a discovery;
8. An acknowledgement form signed by each worker indicating that they have received the training; and
9. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

No ground disturbance shall occur prior to implementation of the WEAP program, unless such activities are specifically approved by the CPM.

Verification

1. At least 30 days prior to the beginning of ground disturbance, the CRS shall provide the training program draft text and graphics and the informational brochure to the CPM for review and approval, and the CPM will provide to the project owner a WEAP Training Acknowledgement form for each WEAP-trained worker to sign.

2. On a monthly basis, until ground disturbance is completed, the project owner shall provide in the Monthly Compliance Report (MCR) the WEAP Training

   Acknowledgement forms of workers at the project site and on the linear facilities who have completed the training in the prior month and a running total of all persons who have completed training to date.

CUL-6 The project owner shall ensure that the CRS, alternate CRS, or CRMs monitor full time all ground disturbance at the project site, along the linear facilities routes, and at laydown areas, roads, and other ancillary areas, to ensure there are no impacts to undiscovered resources and to ensure that known resources are not impacted in an unanticipated manner.

Full-time archaeological monitoring for this project shall be the archaeological monitoring of all ground-disturbing activities on the project site, at the laydown area, along the linear facility routes, and at roads or other ancillary areas, for as long as the activities are ongoing. Full-time archaeological monitoring shall require at least one monitor per excavation area where machines are actively disturbing native soils. If an excavation area exceeds 1,000 square meters, one additional monitor shall be retained to observe each additional 1,000 square meter excavation area.

In the event that the CRS believes that the current level of monitoring is not appropriate in certain locations, a letter or e-mail detailing the justification for changing the level of monitoring shall be provided to the CPM for review and approval prior to any change in the level of monitoring.

The research design in the CRMMP shall govern the collection, treatment, retention/disposal, and curation of any archaeological materials encountered.

On forms provided by the CPM, CRMs shall keep a daily log of any monitoring and other cultural resources activities and any instances of non-compliance with the Conditions and/or applicable LORS. Copies of the daily monitoring logs shall be provided by the CRS to the CPM, if requested by the CPM. From these logs, the CRS shall compile a monthly monitoring summary report to be included in the MCR. If there are no monitoring activities, the summary report shall specify why monitoring has been suspended. The CRS or alternate CRS shall report daily to the CPM on the status of cultural resources-related activities at the project site, unless reducing or ending daily reporting is requested by the CRS and approved by the CPM.

The CRS, at his or her discretion, or at the request of the CPM, may informally discuss cultural resources monitoring and mitigation activities with Energy Commission technical staff.

Cultural resources monitoring activities are the responsibility of the CRS. Any interference with monitoring activities, removal of a monitor from duties assigned by the CRS, or direction to a monitor to relocate monitoring activities by anyone other than the CRS shall be considered non-compliance with these Conditions.

Upon becoming aware of any incidents of non-compliance with the Conditions and/or applicable LORS, the CRS and/or the project owner shall notify the CPM by telephone or e-mail within 24 hours. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the Conditions. When the issue is resolved, the CRS shall write a report describing the issue, the resolution of the issue, and the effectiveness of the resolution measures. This report shall be provided in the next MCR for the review of the CPM.

A Native American monitor shall be obtained to monitor ground disturbance in areas where Native American artifacts may be discovered. Contact lists of interested Native Americans and guidelines for monitoring shall be obtained from the Native American Heritage Commission. Preference in selecting a monitor shall be given to Native Americans with traditional ties to the area that shall be monitored. If efforts to obtain the services of a qualified Native American monitor are unsuccessful, the project owner shall immediately inform the CPM. The CPM will either identify potential monitors or will allow ground disturbance to proceed without a Native American monitor.

<u>Verification</u>

1. At least 30 days prior to the start of ground disturbance, the CPM will provide to the CRS an electronic copy of a form to be used as a daily monitoring log. While monitoring is on-going, the project owner shall include in each MCR a copy of the monthly summary report of cultural resources-related monitoring prepared by the CRS and shall attach any new DPR 523A forms completed for finds treated prescriptively, as specified in the CRMMP.

2. Daily, as long as no cultural resources are found, the CRS shall provide a statement that “no cultural resources over 50 years of age were discovered” to the CPM as an email, or in some other form acceptable to the CPM. If the CRS concludes that daily reporting is no longer necessary, a letter or e-mail providing a detailed justification for the decision to reduce or end daily reporting shall be provided to the CPM for review and approval at least 24 hours prior to reducing or ending daily reporting.

3. At least 24 hours prior to implementing a proposed change in monitoring level, documentation justifying the change shall be submitted to the CPM for review and approval.

4. No later than 30 days following the discovery of any Native American cultural materials, the project owner shall submit to the CPM copies of the information transmittal letters sent to the Chairpersons of the Native American tribes or groups who requested the information. Additionally, the project owner shall submit to the CPM copies of letters of transmittal for all subsequent responses to Native American requests for notification, consultation, and reports and records and any comments or information, provided in response by the Native Americans.

CUL-7 The project owner shall grant authority to halt project-related ground disturbance to the CRS, alternate CRS, and the CRMs in the event of a discovery. Redirection of ground disturbance shall be accomplished under the direction of the construction supervisor in consultation with the CRS.

In the event that cultural resources over 50 years of age are found, or, if younger, determined exceptionally significant by the CPM, or impacts to such resources can be anticipated, ground disturbance shall be halted or redirected in the immediate vicinity of the discovery sufficient to ensure that the resource is protected from further impacts. Monitoring and daily reporting as provided in **CUL-6** shall continue during all ground-disturbing activities elsewhere on the project site. The halting or redirection of ground disturbance shall remain in effect until the CRS has visited the discovery, and all of the following have occurred:

1. The CRS has notified the project owner, and the CPM has been notified within 24 hours of the discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning, including a description of the discovery (or changes in character or attributes), the action taken (i.e., work stoppage or redirection), a recommendation of CRHR eligibility, and recommendations for mitigation of any cultural resources discoveries, whether or not a determination of CRHR eligibility has been made.

2. If the discovery is prehistoric or ethnographic, the CRS has notified all Native American groups that expressed a desire to be notified in the event of such a discovery.

3. The CRS has completed field notes, measurements, and photography for a DPR 523 “Primary” form. Unless the find can be treated prescriptively, as specified in the CRMMP, the “Description” entry of the DPR 523 “Primary” form shall include a recommendation on the CRHR eligibility of the discovery. The project owner shall submit completed forms to the CPM.

4. The CRS, the project owner, and the CPM have conferred, and the CPM has concurred with the recommended eligibility of the discovery and approved the CRS’s proposed data recovery, if any, including the curation of the artifacts, or other appropriate mitigation; and any necessary data recovery and mitigation have been completed.

Verification

1. At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM and CRS with a letter confirming that the CRS, alternate CRS, and CRMs have the authority to halt project-related ground disturbance in the vicinity of a cultural resources discovery, and that the project owner shall ensure that the CRS notifies the CPM within 24 hours of a discovery, or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning.

2. Within 48 hours of the discovery of an archaeological or ethnographic resource, the project owner shall ensure that the CRS notifies all Native American groups that expressed a desire to be notified in the event of such a discovery.

3. Unless the discovery can be treated prescriptively, as specified in the CRMMP, completed DPR 523 forms for resources newly discovered during ground disturbance shall be submitted to the CPM for review and approval no later than 24 hours following the notification of the CPM, or 48 hours following the completion of data recordation/recovery, whichever the CRS decides is more appropriate for the subject cultural resource.

CUL-8 If fill soils must be acquired from a non-commercial borrow site or disposed of to a non-commercial disposal site, unless less-than-five-year-old surveys of these sites for archaeological resources are documented to and approved by the CPM, the CRS shall survey the borrow and/or disposal site/s for cultural resources and record on DPR 523 forms any that are identified. When the survey is completed, the CRS shall convey the results and recommendations for further action to the project owner and the CPM, who will determine what, if any, further action is required. If the CPM determines that significant archaeological resources that cannot be avoided are present at the borrow site, **CUL-6** and **CUL-7** shall apply. The CRS shall report on the methods and results of these surveys in the final CRR.

Verification

1. As soon as the project owner knows that a non-commercial borrow site and/or disposal site will be used, he/she shall notify the CRS and CPM and provide documentation of previous archaeological survey, if any, dating within the past five years, for CPM approval.

2. In the absence of documentation of recent archaeological survey, at least 30 days prior to any soil borrow or disposal activities on the non-commercial borrow and/or disposal sites, the CRS shall survey the site/s for archaeological resources. The CRS shall notify the project owner and the CPM of the results of the cultural resources survey, with recommendations, if any, for further action.

CULTURAL RESOURCES ACRONYM GLOSSARY

BEACON SOLAR ENERGY PROJECT

AFC	Application for Certification
ARMR	Archaeological Resource Management Report
BSEP	Beacon Solar Energy Project
CCS	cryptocrystalline silicate (Cryptocrystalline silicates are rocks such as flint, chert, chalcedony, or jasper that contain a high percentage of silica (SiO^2), the primary compound that composes quartz.)
CEQA	California Environmental Quality Act
CHRIS	California Historical Resources Information System
Conditions	Conditions of Certification
CRHR	California Register of Historical Resources
CRM	Cultural Resources Monitor
CRMMP	Cultural Resources Monitoring and Mitigation Plan
CRR	Cultural Resource Report
CRS	Cultural Resources Specialist
DPR 523	Department of Parks and Recreation cultural resources inventory form
FAR	fire-affected rock
FSA	Final Staff Assessment
LORS	laws, ordinances, regulations, and standards
MCR	Monthly Compliance Report
MLD	Most Likely Descendent
NAHC	Native American Heritage Commission
NRHP	National Register of Historic Places
OHP	Office of Historic Preservation
PSA	Preliminary Staff Assessment

SHPO State Historic Preservation Officer

Staff Energy Commission cultural resources technical staff

WEAP Worker Environmental Awareness Program

REFERENCES

The *tn: 00000* in a reference below indicates the transaction number under which the item is catalogued in the Energy Commission's Docket Unit. The transaction number allows for quicker location and retrieval of individual items docketed for a case or used for ease of reference and retrieval of exhibits cited in briefs and used at Evidentiary Hearings.

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HAZARDOUS MATERIALS MANAGEMENT

Geoff Lesh, PE and Rick Tyler

SUMMARY OF CONCLUSIONS

Staff's evaluation of the proposed project, along with staff's proposed mitigation measures, indicate that hazardous materials use at the proposed Beacon Solar Energy Project (BSEP) would not present a significant impact on the public. With adoption of the proposed conditions of certification, the proposed project will comply with all applicable laws, ordinances, regulations, and standards (LORS).

INTRODUCTION

The purpose of this **HAZARDOUS MATERIALS MANAGEMENT** analysis is to determine if the proposed BSEP could potentially cause significant impacts on the public from the use, handling, storage, or transportation of hazardous materials at the proposed project site. If significant adverse impacts on the public are identified, Energy Commission staff must evaluate facility design alternatives and additional mitigation measures to reduce those impacts to the extent feasible.

This analysis does not address the potential exposure of workers to hazardous materials used at the proposed project site. Employers must inform employees of hazards associated with their work and provide those employees with special protective equipment and training to reduce the potential of health impacts from the handling of hazardous materials. The **WORKER SAFETY AND FIRE PROTECTION** section of this document describes the protection of workers from those risks.

Other hazardous materials such as mineral and lubricating oils, corrosion inhibitors, herbicides, and acids and bases to control pH will be present at the proposed project site. Hazardous materials used during the construction phase include gasoline, diesel fuel, motor oil, lubricants, and small amounts of solvents and paint. No acutely toxic hazardous materials will be used on-site during construction. None of these materials pose a significant potential for off-site impacts as a result of the quantities on-site, their relative toxicity, their physical states, and/or their environmental mobility. Although no natural gas is stored, the project will involve the handling of moderate amounts of natural gas. Natural gas poses some risk of both fire and explosion. Natural gas will be delivered for the project boilers via a new 17.6-mile 8-inch diameter natural gas pipeline, traveling north from its origin west of California City where it will connect to an existing Southern California Gas Company (SCG) pipeline. There will be no onsite storage of natural gas. (BS 2008a, Sections 2.1, and 5.6.3.3) Detailed engineering and construction of the gas pipeline will be the responsibility of SCG (BS 2008a, Section 2.6.2). The BSEP will also require the transportation of certain liquid and solid hazardous materials to the facility. This document addresses all potential impacts associated with the use, storage, and transport of hazardous materials.

LAWS, ORDINANCES, REGULATION, 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 (LORS)

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)	Establishes a nationwide emergency planning and response program, and imposes 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 to inform 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	Requires that the suppliers of hazardous materials prepare and implement security plans in accordance with U.S. Department of Transportation (DOT) regulations.
49 CFR Part 1572, Subparts A and B	Requires that suppliers of hazardous materials ensure that their hazardous material drivers comply 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.
Title 49, Code of Federal Regulations, Part 190	Outlines gas pipeline safety program procedures.
Title 49, Code of Federal Regulations, Part 191	Addresses the transportation of natural and other gases by pipeline. Requires preparation of annual reports, incident reports, and safety-related condition reports. Also requires operators of pipeline systems to notify the U.S. Department of Transportation

	DOT) of any reportable incident by telephone and submit a follow-up written report within 30 days.
Title 49, Code of Federal Regulations, Part 192	Addresses transportation of natural and other gases by pipeline: Requires minimum federal safety standards, specifies minimum safety requirements for pipelines, and includes material selection, design requirements, and corrosion protection. The safety requirements for pipeline construction vary according to the population density and land use that characterize the surrounding land. This part also contains regulations governing pipeline construction, which must be followed for Class 2 and Class 3 pipelines, and requirements for preparing a pipeline integrity management program.
6 CFR Part 27	The CFATS (Chemical Facility Anti-Terrorism Standard) regulation of the U.S. Department of Homeland Security (DHS) that requires facilities that use or store certain hazardous materials to submit information to the DHS so that a vulnerability assessment can be conducted to determine what certain specified security measures shall be implemented.
State	
California Health and Safety Code, section 25531 to 25543.4	The California Accidental Release Program (Cal-ARP) requires the preparation of a Risk Management Plan (RMP) and Off-site Consequence Analysis (OCA) and submittal to the local Certified Unified Program Authority (CUPA) for approval.
Title 8, California Code of Regulations, Section 5189	Requires facility owners to develop and implement effective safety management plans to ensure that large quantities of hazardous materials are handled safely. While these requirements primarily provide for the protection of workers, they also indirectly improve public safety and are coordinated with the 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.
Title 24, California Code of Regulations,	2007 California Building Code
LOCAL	

Uniform Fire Code, Kern County Code Section 17.32.010	Adopts the Uniform Fire Code, 2000 Edition, into Kern County regulations.

Gas Pipeline

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).
- Class 4: Pipelines in locations within 220 yards of buildings with 4 or more stories above ground in any 1-mile segment.

The natural gas pipeline will be designed to meet California Public Utilities Commission General Order 112-E and 58-A standards as well as various SCG standards. The natural gas pipeline must 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:

- Title 49, Code of Federal Regulations, Part 190 outlines the pipeline safety program procedures;
- Title 49, Code of Federal Regulations, Part 191, Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports, requires operators of pipeline systems to notify the U.S. Department of Transportation of any reportable incident by telephone and then submit a written report within 30 days;
- Title 49, Code of Federal Regulations, Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, specifies minimum safety requirements for pipelines and includes material selection, design requirements, and corrosion protection. The safety requirements for pipeline construction vary according to the population density and land use which characterize the surrounding land. This part contains regulations governing pipeline construction, which must be, followed for Class 2 and Class 3 pipelines.

The Kern County Environmental Health Services Department (KCEHSD) acts as the Certified Unified Program Authority (CUPA), and is responsible for reviewing Hazardous Materials Business Plans. With regard to seismic safety issues, the proposed BSEP site is located in Seismic Risk Zone 4. The construction and design of buildings and vessels storing hazardous materials will meet the seismic requirements of the Uniform Building Code and the California Building Code (BS 2008a, section 2.5.6).

SETTING

Several characteristics of an area in which a project is located affect its potential for an accidental release of a hazardous material. 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 health risks. When wind speeds are low and the atmosphere is stable, dispersion is severely reduced and can lead to increased localized public exposure.

Recorded wind speeds and ambient air temperatures are described in the Air Quality section (5.2.2.2) and Appendix E.1 of the Application for Certification (AFC) (BS 2008a).

TERRAIN CHARACTERISTICS

The location of elevated terrain is often an important factor in assessing potential exposure. An emission plume from an accidental release may impact high elevations before it impacts lower elevations. The topography of the BSEP site is essentially flat at about 2,100 feet above sea level, as are the immediately surrounding areas. Because of the nature of the surrounding area, terrain above stack height is not of concern for the project.

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 large bearing on health risk. There are no sensitive receptors within a 3-mile radius of the project site. Red Rock Elementary School, no longer in use, is located 3-miles northeast of the project boundary. Four residences are within 1-mile of the project site. The nearest receptors are located along the site boundary, approximately one-third of a mile from the proposed location of the power block (BS 2008a, section 5.10.2).

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 examines 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 utilizes the most current acceptable public health exposure levels (both acute and chronic) to protect the public from the effects of an accidental chemical release.

In order to assess the potential of released hazardous materials traveling off-site and affecting the public, staff analyzed several aspects of the proposed use of materials at the facility. Staff recognizes that some hazardous materials must be used at power plants. Therefore, staff conducted its analysis by focusing on the choice and amount of chemicals to be used, the manner in which the applicant will use the chemicals, the manner by which it will be transported to the facility and transferred to facility storage tanks, and the way in which the applicant plans to store those materials on-site.

Staff reviewed the applicant's proposed engineering and administrative controls for hazardous material use. Engineering controls are physical or mechanical systems such as storage tanks or automatic shut-off valves that can prevent a spill of hazardous material from occurring, or that can limit the spill to a small amount or confine it to a small area. Administrative controls are rules and procedures that workers must follow to help either prevent accidents or keep them small if they do occur. Both engineering and administrative controls can act as either methods of prevention or methods of response and minimization. In both cases, the goal is to prevent a spill from moving off-site and harming the public.

Staff reviewed and evaluated the proposed use of hazardous materials, as described by the applicant (BS 2008a, section 5.6). Staff's assessment followed the five steps listed below:

- Step 1: Staff reviewed the chemicals and amounts proposed for on-site use, as listed in Table 5.6-3 of the AFC and determined the need and appropriateness of their use. Only those that are needed and appropriate are allowed to be used. If staff feels that a safer alternative chemical can be used, staff will recommend or require its use, depending upon the impacts posed.
- 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 the 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 size 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 measures also included 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 even with 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 project be allowed to use hazardous materials.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Small Quantity Hazardous Materials

In conducting this analysis, staff determined in Steps 1 and 2 that most of the proposed materials, although present at the proposed facility, pose a minimal potential for off-site impacts since they will be stored in either solid form or in small quantities, have low mobility, low vapor pressure, or low levels of toxicity. These hazardous materials, which were eliminated from further consideration, are discussed briefly below.

During the construction phase of the project, the only hazardous materials proposed for use include paint, cleaners, solvents, gasoline, diesel fuel, motor oil, and lubricants. Any impact of spills or other releases of these materials would be limited to the site because of the small quantities involved, the infrequent use and hence reduced chances of release, and/or the temporary containment berms used by contractors. Petroleum hydrocarbon-based motor fuels, mineral oil, lube oil, and diesel fuel all have very low volatility and would represent limited off-site hazards, even in larger quantities.

During operations, hazardous chemicals such as cleaning agents, lube oil, sulfuric acid, sodium hydroxide, hydrogen gas, diesel fuel and other various chemicals (see **Hazardous Materials Appendix A** for a list of all chemicals proposed to be used and stored at BSEP) would be used and stored on-site and represent limited off-site hazard due to their small quantities, low volatility, and/or low toxicity.

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 hazardous materials: sodium hypochlorite, sodium hydroxide, sulfuric acid, natural gas, and Therminol VP-1.

Large Quantity Hazardous Materials

Sodium Hypochlorite

According to the Table 5.6-3 (BS 2008a), 17,000 gallons of sodium hypochlorite would be stored at the site. Sodium hypochlorite has a low potential to affect the off-site public because its vapor pressure is low and it is in an aqueous solution. In fact, hypochlorite is used at many such facilities as a substitute for chlorine gas, which is much more toxic and much more likely to migrate off-site because it is a gas and is stored in concentrated form under pressure. Thus, the use of a water solution of sodium hypochlorite is much safer to use than the alternative chlorine gas. The amount of sodium hypochlorite that would be stored on the site is below the Reportable Quantity as defined in the Cal-ARP regulations. Based upon staff's knowledge about the use of this material and the modeling of accidental releases, an aqueous solution of sodium hypochlorite poses an insignificant risk to the off-site public. However, the chances for accidental spills during transfer from delivery vehicles to the storage tanks should still be reduced as much as possible. Thus, measures to prevent transfer spills are extremely important and would be required as a standard condition in a Safety Management Plan for delivery of sodium hypochlorite (see Condition of Certification **HAZ-3**).

Sodium Hydroxide

Sodium hydroxide would be stored on site but would not pose a risk of off-site impacts because it has relatively low vapor pressure and thus spills would be confined to the site. Therefore, no further analysis is needed.

Sulfuric Acid

Sulfuric acid would be stored on site but would not pose a risk of off-site impacts because it has relatively low vapor pressure and thus spills would be confined to the site. Therefore, no further analysis is needed.

Natural Gas

Natural gas poses a fire and/or possible explosion risk because of its flammability. Natural gas is composed mostly of methane, but it also contains ethane, propane, nitrogen, butane, isobutene, and isopentane. It is colorless, odorless, tasteless, and lighter than air. Natural gas can cause asphyxiation when methane's concentration exceeds 90%. Methane is flammable when mixed in air at concentrations of 5-14%, which is also its detonation range. Natural gas therefore poses a risk of fire and/or explosion if a release were to occur 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 result in an unconfined vapor cloud explosion than many other fuel gases such as propane or liquefied petroleum gas although an unconfined vapor cloud of natural gas can explode under certain conditions (as demonstrated by the natural gas explosion in Belgium in July 2004).

While natural gas will be used in significant quantities, it will not be stored on-site. It will be delivered via an new 8-inch underground pipeline, buried in disturbed road shoulders, that runs north from its origin west of California City where it will connect to an existing SCG pipeline. The pipeline will be buried four to 10-feet below ground surface, depending on location. 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 85A) requires 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. The Safety

Management Plan proposed by the applicant would address both the handling and use of natural gas and significantly reduce the potential for equipment failure due to 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 were also be evaluated. Current design codes 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 this failure mode 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 particularly relevant to the project area is damage caused by earthquakes. 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, occurred 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, as well as the January 19, 1995 gas explosion in San Francisco, the safety of the gas pipeline is of paramount importance. However, it must be noted that those pipelines that failed were older and not manufactured nor installed to modern code requirements.

The natural gas pipeline for the proposed facility will be constructed, owned, and operated by SCG BS 2008a, section 5.6.3.3). 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 could 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 the Department of Transportation (DOT) statistics, the frequency of incidents resulting in fatalities, injury, or significant economic loss is about 0.25 for all pipeline incidents per 1,000 miles per year, or 2.5×10^{-4} incidents per mile per year (SERA 1993). 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 percent, Corrosion-18 percent, Construction/Material Defects-13 percent, and Other-26 percent.

Outside forces are the primary cause 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. This results 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. In the United States, extensive federal and state pipeline codes and safety enforcement minimize the risk of severe accidents related to natural gas pipelines.

Staff believes the worst case scenario for an off-site natural gas impact is a large rupture of the pipeline caused by improper use of heavy equipment near the pipeline. This worst case scenario would not result in a significant asphyxiation hazard since natural gas disperses to the atmosphere rapidly when released. The worst case scenario is primarily a safety hazard to construction workers and nearby residences. The pipeline owner will mark the pipeline in conformance with State and Federal regulations to lower the probability of this occurring.

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.

Therminol VP-1

Therminol VP1 is the HTF that will be used in the solar panels to collect solar heat and transfer it in order to generate steam to run the steam turbine. Approximately 1.3 million gallons of HTF will be contained in the pipes and heat exchanger. Therminol is a mixture of 73.5 percent diphenyl ether and 26.5 percent biphenyl, and is a solid at temperatures below ~54 °F. Because nighttime temperatures during the winter often drop below 54 °F in the high desert, auxiliary heating is provided to keep Therminol liquid. Therminol can therefore be expected to remain liquid if a spill occurs. While the risk of off-site migration is minimal, Therminol is highly flammable and fires have occurred at other solar generating stations that use it. Staff has assessed the properties of Therminol, and reviewed the record of its use at Solar Electric Generating Stations 8 and 9 at Harper Lake, California. Past leaks, spills, and fires involving this HTF were examined and discussed. It appears that the placement of additional isolation valves in the HTF pipe loops throughout the solar array would add significantly to the safety and operational integrity of the entire system by allowing a loop to be closed if a leak develops in a ball joint, flex-hose, or pipe, instead of closing off the entire HTF system and shutting down the plant. Applicant has proposed including isolation valves for this purpose in the project description (BS 2008a, section 2.5.3.1). Staff therefore proposes Condition of Certification **HAZ-7,** which would require the project owner to install a sufficient number of isolation valves that can be either manually or remotely activated.

Mitigation

Staff believes that this project's use of hazardous materials poses no significant risk but only if mitigation measures are used. These mitigation measures are discussed in this section. The potential for accidents resulting in the release of hazardous materials is greatly reduced by the implementation of a Safety Management Program (see **HAZ-3**), which includes both engineering and administrative controls. Elements of facility controls and the safety management plan are summarized below.

Engineering Controls

Engineering controls help prevent accidents and releases (spills) from moving off-site and impacting the community by incorporating engineering safety design criteria into the project's design. Engineering safety features proposed by the applicant include:

- Usage of secondary containment areas surrounding each of the hazardous materials storage areas, designed to contain accidental releases during storage;
- Physical separation of stored chemicals in isolated containment areas, separated by a noncombustible partition in order to prevent the accidental mixing of incompatible materials, which may in turn cause the formation and release of toxic gases or fumes.

Administrative Controls

Administrative controls help prevent accidents and releases (spills) from moving off-site and impacting the community by establishing worker training programs and process safety management programs.

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/FIRE PROTECTION** section in this PSA for specific regulatory requirements):

- Worker training on 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 that use hazardous materials;
- Fire safety and prevention; and
- Emergency response actions including facility evacuation, hazardous material spill cleanup, and fire prevention.

At BSEP, the project owner will be required to designate an individual who will have the responsibility and authority to ensure a safe and healthful workplace. This project health and safety official will oversee the health and safety program and will have the authority to halt any action or modify any work practice in order to protect the workers, facility, and the surrounding community in the event that the health and safety program is violated.

A Hazardous Materials Business Plan (HMBP) will also be prepared by the applicant (see **HAZ-2**) that would incorporate state requirements for the handling of hazardous materials (BS 2008a, section 5.6.3.3). A Spill Prevention Control and Countermeasure Plan (SPCC) is required by Federal Regulations (see LORS above) and will be prepared for the petroleum-containing hazardous materials.

On-site Spill Response

In order to address spill response, the facility will prepare and implement an emergency response plan which includes information on hazardous materials contingency and emergency response procedures, spill containment and prevention systems, personnel training, spill notification, on-site spill containment, prevention equipment and capabilities, etc. Emergency procedures will be established which include evacuation, spill cleanup, hazard prevention, and emergency response.

A Kern County HazMat team is currently based at Station #14 in Mojave, California, which is located approximately 19 miles from the project site. The Kern County HazMat Team response time to a hazmat emergency call from BSEP would be approximately 23 minutes (Eckroth).

Staff concludes that the hazardous material response time is acceptable, and that the Kern County HazMat Team is adequately trained and equipped to respond to an emergency at BSEP in a timely manner.

Transportation of Hazardous Materials

Containerized hazardous materials including sulfuric acid, and cleaning chemicals, will be transported to the facility via truck. While many types of hazardous materials will be transported to the site, previous modeling of spills involving much larger quantities of toxic materials, (more toxic aqueous ammonia and 93% sulfuric acid) has demonstrated that minimal airborne concentrations would occur at short distances from the spill.

During construction and operation of BSEP, staff believes that minimal amounts and types of hazardous materials (paint, cleaners, solvents, gasoline, diesel fuel, motor oil, lubricants, 29% sulfuric acid, and welding gases in standard-sized cylinders) do not pose a significant risk of either spills or public impacts along any transportation route. Staff therefore does not recommend a specific route.

Liquid hazardous materials can be released during a transportation accident, and the extent of their impact in the event of a release would depend on the location of the accident and the rate of vapor dispersion from the surface of the spilled pool. The likelihood of an accidental release during transport is dependent upon three factors:

- The skill of the tanker truck driver;
- The type of vehicle used for transport; and
- 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 divided California State Highway (SR-58). Staff believes it is appropriate to rely upon the extensive regulatory program that applies to shipment of hazardous materials on California Highways to ensure safe handling in general transportation (see the Federal Hazardous Materials Transportation Law 49 USC §5101 et seq., the U.S. Department of Transportation Regulations 49 CFR Subpart H, §172-700, and the California DMV Regulations on Hazardous Cargo). These regulations also address issues of driver competence. See AFC section 5.13.1 for additional information on regulations governing the transportation of hazardous materials.

Seismic Issues

The possibility exists that an earthquake could cause the failure of a hazardous materials storage tank. A quake could also cause the failure of the secondary containment system (berms and dikes), as well as electrically controlled valves and pumps. The failure of all these preventive control measures might then result in a vapor cloud of hazardous materials that could move off-site and impact 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, heighten concerns about earthquake safety.

Information obtained after the January 1994 Northridge earthquake showed that some damage was caused to several large and small storage tanks at the water treatment system of a cogeneration facility. The tanks with the greatest damage, including seam leakage, were older tanks, while newer tanks sustained lesser damage with displacements and attached line failures. Therefore, staff conducted an analysis of the codes and standards, which should be followed to adequately design and build storage tanks and containment areas that could 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 were impacted by this quake. Referring to the sections on **GEOLOGIC RESOURCES AND HAZARDS** and **FACILITY DESIGN** in the AFC, staff notes that the proposed facility will be designed and constructed to the applicable standards of the 2007 California Building Code for Seismic Zone 4 (BS 2008a, section 5.6.3.3). Therefore, on the basis of occurrences at Northridge with older tanks and the lack of failures during the Nisqually earthquake with newer tanks, staff determined that tank failures during seismic events are not likely and do not represent a significant risk to the public.

Site Security

BSEP proposes to use hazardous materials identified by the US EPA as materials where special site security measures should be developed and implemented to prevent unauthorized access. US EPA published a *Chemical Accident Prevention Alert* regarding site security (EPA 2000a), the U.S. Department of Justice published a special report on Chemical Facility Vulnerability Assessment Methodology (US DOJ 2002), the North American Electric Reliability Corporation (NERC) published *Security Guidelines for the Electricity Sector* in 2002 (NERC 2002), and the U.S. Department of Energy published a 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 facilities that use or store certain hazardous materials to 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. Staff 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.

In order to ensure that this facility (or a shipment of hazardous material) is not the target of unauthorized access, staff's proposed conditions of certification **HAZ-5** and **HAZ-6** address both construction security and operations security plans. These plans would require the implementation of site security measures that are consistent with both the above-referenced documents and Energy Commission guidelines.

The goal of these conditions of certification is to provide the minimum level of security for power plants needed to protect California's electrical infrastructure from malicious mischief, vandalism, or domestic/foreign terrorist attacks. The level of security needed for this power plant 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 consequences of that 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 NERC 2002 guidelines, the U.S. Department of Energy VAM-CF model, and U.S. Department of Homeland Security regulations published in the Federal Register (Interim Final Rule 6 CFR Part 27). Staff determined that BSEP would fall into the "low vulnerability" category, so staff 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, possibly guards, alarms, site access procedures for employees and vendors, site personnel background checks, and law enforcement contact in the event of a security breach. Site access for vendors will 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 fleets and employ only drivers who are properly licensed and trained. The project owner will be required, through its contractual language with vendors, to ensure that vendors supplying hazardous materials strictly adhere to the U.S. DOT requirements that hazardous materials vendors prepare and implement security plans per 49 CFR 172.800 and ensure that all hazardous materials drivers are in compliance with personnel background security checks 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. Department of Energy, or NERC, after consultation with appropriate law enforcement agencies and the applicant.

CUMULATIVE IMPACTS AND MITIGATION

Staff considered the potential for impacts due to a simultaneous release of any of the hazardous chemicals from the proposed BSEP with any other nearby facilities. Because of the small amounts of the hazardous chemicals to be stored at the facility, Staff determined that there was practically no possibility of producing an offsite impact. Because of this determination, and the additional fact that there are no nearby facilities using large amounts of hazardous chemicals, there is little (if any) possibility that vapor plumes would mingle (combine) to produce an airborne concentration that would present a significant risk.

COMPLIANCE WITH LORS

Staff concludes that construction and operation of BSEP would be in compliance with all applicable LORS for both long-term and short-term project impacts in the area of hazardous materials management.

CONCLUSIONS

Staff's evaluation of the proposed project (with proposed mitigation measures) indicates that hazardous material use, storage, and transportation will not pose a significant impact on 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. Other proposed conditions of certification address the issues of site security matters.

Staff recommends that the Energy Commission impose the proposed conditions of certification, presented below, to ensure that the project is designed, constructed, and operated in compliance with applicable LORS, and will protect the public from significant risk of exposure to an accidental release of hazardous materials. If all mitigation proposed by the applicant and by staff are implemented, the use, storage, and transportation of hazardous materials will not present a significant risk to the public.

Staff proposes six conditions of certification, some of which are mentioned in the text (above), and listed below. **HAZ-1** ensures that no hazardous material would be used at the facility except as listed in the AFC, unless there is prior approval by the Energy Commission Compliance Project Manager.

HAZ-3 requires the development of a Safety Management Plan that addresses the delivery of all liquid hazardous materials during the construction, commissioning, and operation of the project will further reduce the risk of any accidental release not specifically addressed by the proposed spill prevention mitigation measures, and further prevent the mixing of incompatible materials that could result in the generation of toxic vapors. Site security during both the construction and operation phases is addressed in **HAZ-4** and **HAZ-5.**

PROPOSED CONDITIONS OF CERTIFICATION

HAZ-1 The project owner shall not use any hazardous materials not listed in **Appendix A**, below, or in greater quantities than those identified by chemical name in **Appendix A,** 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 Business Plan to the Kern County Environmental Health Services Department (KCEHSD) and the CPM for review. After receiving comments from the KCEHSD and the CPM, the project owner shall reflect all recommendations in the final documents. Copies of the final Business Plan shall then be provided to the KCEHSD for information and to the CPM for approval.

Verification: At least 60 days prior to receiving any hazardous material on the site for commissioning or operations, the project owner shall provide a copy of a final Business Plan to the CPM for approval.

HAZ-3 The project owner shall develop and implement a Safety Management Plan for delivery of liquid hazardous materials. 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. This plan shall be applicable during construction, commissioning, and operation of the power plant.

Verification: At least sixty (60) days prior to the delivery of any liquid hazardous material to the facility, the project owner shall provide a Safety Management Plan as described above to the CPM for review and approval.

HAZ-4 At least thirty (30) days 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.

<u>Verification:</u> 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-5 The project owner shall prepare a site-specific Security Plan for the operational phase and shall be made available to the CPM for review and approval. The project owner shall implement site security measures addressing 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 eight feet high around the Power Block and Solar Field;

2. Main entrance security gate, either hand operable 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 ascertain the accuracy of employee identity and employment history, and shall be conducted in accordance with state and federal law 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 contractor personnel that visit the project site.

7. Site access controls for employees, contractors, vendors, and visitors;

8. 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

9. Additional measures to ensure adequate perimeter security consisting of either:

   a. Security guard present 24 hours per day, seven days per week, **OR**

   b. Power plant personnel on-site 24 hours per day, seven days per week and **all** of the following:

      1) The CCTV monitoring system required in number 8 above shall include cameras that are able to pan, tilt, and zoom (PTZ), have low-light capability, are recordable, and are able to view 100% of the perimeter fence, 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 the security plans. The CPM may authorize modifications to these measures, or may require additional measures, such as protective barriers for critical power pant components (e.g., transformers, gas lines, compressors, etc.) depending on 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 appropriate law enforcement agencies and the applicant.

<u>Verification:</u> At least 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 updated certification statements are 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-6 The project owner shall ensure that the hydrogen gas storage cylinders are stored in an area out of area potentially affected by a turbine over-speed accident and that no combustible or flammable material is stored within 50 feet of the hydrogen cylinders.

Verification: At least sixty (60) days prior to receipt of hydrogen gas on-site, the project owner shall provide copies of the facility design drawings showing the location of the hydrogen gas cylinders and the location of any tanks, drums, or piping containing any combustible or flammable material and the route by which such materials will be transported through the facility.

HAZ-7 The project owner shall place an adequate number of isolation valves in the Heat transfer Fluid (HTF) pipe loops so as to be able to isolate a solar panel loop in the event of a leak of fluid. These valves shall be actuated manually and remotely. The engineering design drawings showing the number, location, and type of isolation valves shall be provided to the CPM for review and approval prior to the commencement of the solar array construction.

Verification: At least sixty (60) days prior to the commencement of solar array construction, the project owner shall provide the design drawings as described above 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.

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Hazardous Materials
Appendix A

Hazardous Materials Proposed for Use
At the
BSEP Power Project
March 2008

Source: BS 2008a, Table 5.6-2

Table 5.6-3 Summary of Special Handling Precautions for Large Quantity Hazardous Materials

Hazardous Material	Relative Toxicity[1] and Hazard Class[2]	Permissible Exposure Limit	Storage Description; Capacity	Storage Practices and Special Handling Precautions
Natural Gas (methane)	Low toxicity; Hazard class – Flammable gas	None Established	No on site storage, up to 140 pounds of natural gas in equipment and piping; pressurized carbon steel pipeline for delivery to site	No storage on site. Piping will be designed to U.S. Department of Transportation (DOT) specifications; onsite facilities (gas metering) will be designed and operated to industry standards.
Hydrogen	Low toxicity; Hazard class – Flammable gas	None Established	In generator cooling loop and "tube trailer"; total inventory of 63,000 SCF (335 pounds)	Pressure safety tank, crash posts, pressure relief valves
Sodium Hydroxide, 50% solution	High toxicity; Hazard class – Corrosive	PEL: 2 mg/m^3	Carbon steel tank; 8,500 gallons	Isolated from incompatible chemicals and secondary containment
Sodium Hypochlorite, 12.5% solution	High toxicity; Hazard class – Poison-B, Corrosive	Workplace Environmental Exposure Limit (WEEL) - STEL: 2 mg/m3 PEL: 0.5 ppm (TWA), STEL: 1 ppm as Chlorine TLV: 1 ppm (TWA), STEL: 3 ppm as Chlorine	Plastic tanks; 17,000 gallons total inventory (2 x 8,500 gallons)	Secondary containment
Sulfuric Acid, 29.5% solution	High toxicity; Hazard class – Corrosive, water reactive	PEL: 1 mg/m^3	Contained in batteries; 2,000 gallons total inventory	Isolated from incompatible chemicals and secondary containment
Sulfuric Acid, 93% solution	High toxicity; Hazard class – Corrosive, water reactive	PEL: 1 mg/m^3	Lined, carbon steel tanks; 16,000 gallons total inventory (2 x 8,000 gallons)	Isolated from incompatible chemicals, lined tank, and secondary containment

Hazardous Material	Relative Toxicity[1] and Hazard Class[2]	Permissible Exposure Limit	Storage Description; Capacity	Storage Practices and Special Handling Precautions
Carbon Dioxide	Low toxicity; Hazard class – Non flammable gas	TLV: 5,000 ppm (9,000 mg/m^3) TWA	Carbon steel tank, 15 tons maximum onsite inventory	Carbon steel tank with crash posts
Therminol VP-1 Diphenyl ether (73.5%) Biphenyl (26.5%)	Moderate toxicity, Hazard class – Irritant; Combustible Liquid (Class III-B)	Biphenyl = PEL: 0.2 ml/m^3 (8-hr TWA) TLV: 0.2 ml/m^3 (1 mg/m^3) (8-hr TWA) Diphenyl ether = TLV: 1 ml/m^3(8-hr TWA) TLV: 2 ml/m^3(15-min TWA) PEL: 1 ml/m^3 (7 mg/m^3) (15-min TWA)	1.3 MM gallons in system, no additional onsite storage	Continuous monitoring of pressure in piping network; routine inspections (sight, sound, smell) by operations staff; isolation valves throughout piping network to minimize fluid loss in the event of a leak; prompt clean up and repair.
Lube Oil	Low toxicity Hazard class – NA	None established	Carbon steel tanks, 10,000 gallons in equipment and piping, additional maintenance inventory of up to 550 gallons in 55-gallon steel drums.	Secondary containment for tank and for maintenance inventory
Mineral Insulating Oil	Low toxicity Hazard class – NA	None established	Carbon steel transformers; total onsite inventory of 32,000 gallons	Used only in transformers, secondary containment for each transformer
Diesel Fuel	Low toxicity; Hazard class – Combustible liquid	PEL: none established TLV: 100 mg/m^3	Carbon steel tank (300 gallons)	Stored only in fuel tank of emergency engine, secondary containment.
Nitrogen	Low toxicity; Hazard class – Non flammable gas	None established	Carbon steel tank; 7,500 pounds total inventory	Carbon steel tank with crash posts

Hazardous Material	Relative Toxicity[1] and Hazard Class[2]	Permissible Exposure Limit	Storage Description; Capacity	Storage Practices and Special Handling Precautions
Water treatment chemical NALCO Acti-Brom (R) 7342 Sodium bromide	Low toxicity; Hazard class – Irritant	Sodium bromide = PEL: none established	Plastic totes, 2 x 400 gallons	Inventory management, isolated from incompatible chemicals and secondary containment
Water treatment chemical NALCO pHreedom® 5200M Sodium salt of phosphonomethylated diamine	Low to moderate toxicity; Hazard class – Irritant	Sodium salt of phosphonomethylated diamine = PEL: none established	Plastic totes, 2 x 400 gallons	Inventory management, isolated from incompatible chemicals and secondary containment
Water treatment chemical NALCO PCL-1346	Low toxicity; Hazard class – Irritant	None established for mixture	Plastic totes, 2 x 400 gallons	Inventory management, isolated from incompatible chemicals and secondary containment
Water treatment chemical NALCO Permacare (R) PC-7408 Sodium bisulfite	Low toxicity; Hazard class – Irritant	Sodium bisulfite = PEL: none established: TLV: 5 mg/m^3 TWA	Plastic totes, 2 x 400 gallons	Inventory management, isolated from incompatible chemicals and secondary containment
Water treatment chemical NALCO BT-3000 Sodium hydroxide Sodium tripolyphosphate	High toxicity; Hazard class – Corrosive	Sodium hydroxide = PEL: 2 mg/m^3 Sodium tripolyphosphate = PEL: none established	Plastic totes, 2 x 400 gallons	Inventory management, isolated from incompatible chemicals and secondary containment
Water treatment chemical NALCO 8338 Sodium nitrite Sodium tolytriazole Sodium hydroxide	Moderate toxicity; Hazard class – Toxic	Sodium nitrite = PEL: none established Sodium tolytriazole = PEL: none established Sodium hydroxide = PEL: 2 mg/m^3	Plastic totes, 2 x 400 gallons	Inventory management, isolated from incompatible chemicals and secondary containment

Hazardous Material	Relative Toxicity[1] and Hazard Class[2]	Permissible Exposure Limit	Storage Description; Capacity	Storage Practices and Special Handling Precautions
Welding gas Acetylene	Moderate toxicity; Hazard class – Toxic	PEL: none established	Steel cylinders; 200 cubic foot each, 800 cubic foot total on site	Inventory management, isolated from incompatible chemicals,
Welding gas Oxygen	Low toxicity; Hazard class – Oxidizer	PEL: none established	Steel cylinders; 200 cubic foot each, 800 cubic foot total on site	Inventory management, isolated from incompatible chemicals
Welding gas Argon	Low toxicity; Hazard class – Nonflammable gas	PEL: none established	Steel cylinders; 200 cubic foot each, 800 cubic foot total on site	Inventory management
Fertilizer Urea	Low toxicity; Hazard class - NA	WEEL: 10 mg/m^3, 8-hour TWA	Stored in bags (dry pellets), 5 x 50-pound, 250 pound total inventory	Inventory management, indoor storage
Fertilizer Monopotassium phosphate	Low toxicity; Hazard class - Irritant	TLV: 10 mg/m^3 (inhalable) 8-hr TWA, 3 mg/m^3 (respirable) 8-hr TWA PEL: 15 mg/m^3 (total dust) 8-hr TWA, 5 mg/m^3 (respirable) 8-hr TWA	Stored in bags (dry pellets), 5 x 50-pound, 250 pound total inventory	Inventory management, indoor storage
Activated Carbon	Non-toxic (when unsaturated), low to moderate toxicity when saturated, depending on the adsorbed material; Hazard class – combustible solid	TWA (total particulate): 15 mg/m^3 TWA (respirable fraction): 5 mg/m^3 TLV (graphite, all forms except graphite fibers): 2 mg/m^3 TWA	Used in two x 2,000-lb canisters, 4,000 pounds total inventory, no additional storage	No excess inventory stored onsite, prompt disposal when spent
Herbicide Roundup® or equivalent	Low toxicity; Hazard class - Irritant	Isoproplyamine salt of glyphosphate = no specific occupational exposure has been established	No onsite storage, brought on site by licensed contractor, used immediately	No excess inventory stored onsite

Hazardous Material	Relative Toxicity[1] and Hazard Class[2]	Permissible Exposure Limit	Storage Description; Capacity	Storage Practices and Special Handling Precautions
Soil stabilizer Active ingredient: acrylic or vinyl acetate polymer or equivalent	Non-toxic; Hazard class - NA	None established	No onsite storage, supplied in 55-gallon drums or 400gallon totes, used immediately	No excess inventory stored onsite

[1] Low toxicity is used to describe materials with an NFPA Health rating of 0 or 1. Moderate toxicity is used describe materials with an NFPA rating of 2. High toxicity is used to describe materials with an NFPA rating of 3. Extreme toxicity is used to describe materials with an NFPA rating of 4. [2] NA denotes materials that do not meet the criteria for any hazard class defined in the 1997 Uniform Fire Code.

LAND USE

James Adams

SUMMARY OF CONCLUSIONS

Staff has provided findings of conformity and conditions of certification that would bring the Beacon Solar Energy project in conformity with the Kern County General Plan and Ordinance Code.

Energy Commission staff concludes that Beacon Solar Energy project would not:

- Result in any impacts to existing agricultural operations or future use; convert farmland to non-agricultural use; or conflict with existing agricultural zoning or Williamson Act contracts;
- Physically disrupt or divide an established community;
- Conflict with any applicable habitat conservation plan or natural community conservation plan; or
- Result in unmitigated project-related impacts on surrounding land uses.

INTRODUCTION

The land use analysis of the Beacon Solar Energy project (BSEP) focuses on the project's consistency with land use plans, ordinances, regulations, and policies, and the project's compatibility with existing or reasonably foreseeable land uses. The project would occupy over 2,000 acres in eastern Kern County. The site is currently vacant but did support some agricultural activities back in the early 1980s (BSEP 2008a, pg. 2-3).

SETTING

The project site is located along the eastern side of State Route (SR) -14 about four miles north-northwest of California City's northern boundary, 15 miles north of the town of Mojave, and 24 miles northeast of the city of Tehachapi (Ibid, pg 1-2). The project area is lightly populated with about 35 to 40 single family residences on 2.5-acre to 10-acre parcels within a community called Cantil, which is just north of BSEP site. Land surrounding the project site, and the project site itself, is largely undeveloped, flat, desert terrain. The closest residence is approximately 0.3-mile north of the nearest project site boundary. The applicant is considering two relatively similar options for connecting with the Los Angeles Department of Water and Power's 230 kV Barren Ridge Switching Station, which is on the west side of SR-14 about 1.5 miles southwest of the project site (see **Land Use Figure 1**).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following table contains all land use LORS applicable to the proposed project.

Land Use Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	**Description**
Federal	None
State California Government Code Sections 65352, 65940, and 65944	Requires evaluation of compatibility with military activities for any land use proposal located near a military installation or airspace.
Local	
Kern County	
General Plan (2007) Land Use, Open Space, and Conservation Element	Relevant resource designations include areas with existing uses or potential uses for intensive agriculture or resource management. The resource management has a goal to encourage alternative sources of energy, such as wind and solar.
Energy Element Chapter 5.4.5 – Solar Energy Development	This section has a singular goal of encouraging safe and orderly commercial solar development. Relevant policies are: encourage domestic and commercial solar energy uses to conserve fossil fuel; attempt to identify and remove disincentives to domestic and commercial solar energy development; and permit solar energy development in the desert and valley planning regions that have been previously disturbed, and does not pose significant environmental, public health, and safety hazards. The County is committed to working with state and federal agencies and interest groups to establish consistent policies for solar energy development.
Military Readiness Element	This element will consider the impact of new growth on military readiness activities. This includes activities within the R-2508 Special Use Airspace Complex which overlies the project site.
Airport Land Use Compatibility Plan Policy 1.7c	Prior to the approval of a proposal involving any type of land use development…specific findings shall be made that such development is compatible with the training and operational missions of the military aviation installations. Incompatible land uses that result in significant impacts to the military mission of Department of Defense installations or to the Joint Service Restricted R-2508 Complex that cannot be mitigated, shall not be considered consistent with this plan.
Ordinance Code (2005)	Ordinance codes dealing with exclusive agriculture and limited agriculture lands allow for solar energy electrical generators, commercial or domestic, exceeding five kilowatts.

GENERAL PLAN LAND USE DESIGNATIONS AND ZONING WITHIN THE ONE-MILE RADIUS OF THE PROJECT STUDY AREA

The Beacon Solar Energy plant site, construction laydown areas, power block, and both transmission line option routes are all located within designated agricultural zones and parts of the project site are in flood and seismic hazard zones (see **Land Use Figure 2**). The two transmission routes are also displayed on **Land Use Figure 1** as is the 17.6-mile natural gas pipeline. The applicant's Data Response Land 2 indicates that Beacon Solar owns 26 of the 29 separate parcels of the 2,012-acre site for the project and is in the process of acquiring the remaining three (BSEP 2008b). The construction parking area would also be located onsite.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Energy Commission staff has analyzed the information provided in the Application for Certification (AFC) and acquired from other sources to determine consistency of the BSEP with applicable federal, state, and local LORS and the potential for the project to have significant adverse land use-related impacts. Staff has also assessed mitigation measures proposed by the applicant and conditions developed by staff to reduce any potential impacts to a less than significant level, as well as the feasibility and enforceability of those proposed mitigation measures and recommended conditions of certification.

METHOD AND THRESHOLDS FOR DETERMINING SIGNIFICANCE

State/CEQA

Significance criteria used in this document are based on the California Environmental Quality Act (CEQA) Guidelines and LORS utilized by other governmental agencies. Land use impacts may be considered significant if the project would:

- Involve the conversion of Farmland
  - o Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to non-agricultural use.
  - o Conflict with existing zoning for agricultural use or a Williamson Act contract.
  - o Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland to non-agricultural uses.
- Physically disrupt or divide an established community.
- Conflict with any applicable habitat conservation plan or natural community conservation plan.
- Preclude, interfere with, or unduly restrict existing or future permitted uses.
- Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction, or that would normally have jurisdiction, over the project. This includes, but is not limited to, a General Plan, community or specific plan, local coastal program, airport land use compatibility plan, or zoning ordinance.

- Have individual environmental effects which, when considered with other impacts from the same project or in conjunction with impacts from other closely related past, present, and reasonably foreseeable future projects, are considerable, compound, or increase other environmental impacts.

In general, a power plant and its related facilities may also be incompatible with existing or planned land uses, resulting in potentially significant impacts, if it creates unmitigated noise, dust, or a public health or safety hazard or nuisance; or results in adverse traffic or visual impacts. Please see other sections of this document, as noted, for a detailed discussion of any additional potential project impacts, recommended mitigation, and conditions of certification. **Land Use Table 2** provides a summary of the consistency of the BSEP with the applicable land use LORS adopted by the federal government, the state of California, and Kern County as identified in **Land Use Table 1**. Conditions of certification have been proposed to make the project consistent with the LORS, where necessary.

Based on Energy Commission staff's independent review of the AFC and local Ordinance Code, staff has determined that the project would comply with all land use LORS for Kern County. Energy Commission staff has proposed Condition of Certification **LAND-1** as a means of verifying that the project, if certified, would be built, in accordance with the county's minimum agricultural and building zoning ordinance titles.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Conversion of Farmland

As noted above, the project site was used for intensive agricultural activities. This occurred in the mid 1980s and because no land has been irrigated since 2000, the property is not designated as "farmland" in the Farmland Mapping and Monitoring Program maintained by the California Department of Conservation (CDOC 2008). There are no lands within the project site under the control of the Williamson Act. Neither the construction nor operational activities of the proposed project would result in any impacts to existing agricultural operations or foreseeable future agricultural use. Therefore, the proposed project would not result in the conversion of farmland to non-agricultural use or conflict with existing agricultural zoning or Williamson Act contracts. The existing zoning of the project site allows for solar energy electrical generators. The project would have no impact with respect to farmland conversion.

Physical Division of an Existing Community

The proposed BSEP site is located near the community of Cantil which is designated as a Special Treatment Area as noted in Kern County General Plan Chapter 1.5 (kern County 2004). These areas are generally small rural communities located throughout the county that are historically identifiable as a mixture of residential and supportive commercial and other uses serving the community and the surrounding population. The county is committed to ensuring that these communities retain their unique character and that they are preserved and enhanced by recognizing the scale, density, size, and composition of development. The northern portion of the plant site is within the Cantil Rural Community Area as designated in Map Unit 5.6 of the Residential chapter within the Special Treatment Areas section of the General Plan. The applicable goal in this chapter is to minimize land use conflicts between residential and resource, commercial, or industrial land uses (Ibid, pg. 35). The applicants Figure 5.7-5 from the AFC shows the project's footprint on the Cantil Community Area is bounded to the north by Richards Avenue and to the west by Sixtieth Street. The BSEP would not divide this community.

Conflict with any Applicable Habitat or Natural Community Conservation Plan

The proposed project site is not subject to any Habitat or Natural Community Conservation Plan or within the boundaries of any wildlife preserve or critical habitat area.

Conflict with any Applicable Land Use Plan, Policy, or Regulation

As required by California Code of Regulations, section 1744, Energy Commission staff evaluates the information provided by the applicant in the AFC to determine if elements of the proposed project would conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project, or that would normally have jurisdiction over the project except for the Energy Commission's exclusive authority. This includes all applicable federal, state, and local laws, ordinances, regulations, and standards, including those adopted by Kern County. From a CEQA perspective, the analysis places particular emphasis on any environmental effect that may be avoided or mitigated by conformity with the applicable LORS.

Kern County General Plan

The BSEP is located within the jurisdiction of Kern County. Land use and zoning designations for the site include agriculture (exclusive and limited), platted lands, and seismic and flood hazards (BSEP 2008a, Figure 5.7-6). The project represents a significant change to the existing use of the property which has been vacant land since the mid-1980s, when intensive agricultural activities ceased operation.

As shown in Figure 5.7-6, portions of the BSEP site are in seismic (Alquist-Priolo Earthquake Fault Zone) and flood hazard (Pine Creek) areas as described in the Physical and Environmental Constraint chapter of the Land Use, Open Space, and Conservation Element of the General Plan. Policy #10 states that…"the County will allow lands which are within flood hazard areas, other than primary floodplains, to be developed in accordance with the General Plan and Floodplain Management Ordinance, if mitigation measures are incorporated so as to ensure that the proposed development will not be hazardous within the requirements of the Safety Element of the General Plan" (Kern County 2006, pg. 13). The applicant has identified relevant implementation measures from the Physical and Environment Constraint chapter that staff considers reasonable.

H. Development within areas subject to flooding, as defined by the appropriate agency, will require necessary flood evaluations and studies.

I. Designated flood channels and water courses, such as creeks, gullies, and riverbeds, will be preserved as resource management areas.

J. Compliance with the Floodplain Management Ordinance prior to grading or improvement of land for development or the construction, expansion, conversion or substantial improvements of a structure is required.

Staff is aware that a portion of Pine Tree Creek and an un-named flood wash on the project site will be rerouted to the south and east; but the portions of the creek and wash will be preserved in the new channel, and the BSEP would be consistent with implementation measure I (see the **Water Resources** and **Biology** sections for additional information).

The Kern County General Plan also has an Energy Element which has a primary objective of promoting and facilitating energy development. As noted in **Land Use Table 1**, one of the energy related goals is encouraging commercial solar development. Therefore, the project is consistent with the Kern County General plan.

The BSEP power block and solar arrays will occupy 1,266 acres of the 2,012-site while rerouted drainage canal, evaporation ponds, access road, administration buildings and other support facilities, bioremediation areas, and some open areas would take up the rest of the project site (BSEP 2008a, pg. 2-3). Some existing unpaved roadways and future road corridors on the BSEP site would be removed from service but the county has indicated that this impact can be mitigated by an amendment to the Circulation Element of the Kern County General Plan (Ibid pg. 5.7-6). Staff has been advised by Kern County staff that an amendment to the Circulation Element will go before the Kern County Board of Supervisors at their April 21, 2009 board meeting. The amendment is supported by Kern County staff (Kern County 2009).

The new transmission line would extend west across SR-14 and take one of two routes. The first 3.5-mile route would head south and connect with the existing Barren Ridge Switching Station. The second 2.3-mile route would continue west and hook up with a new switching station where the project's transmission line would meet Los Angeles Department of Water and Power's existing transmission right-of-way. An additional one-mile line would be built that would head south to the Barren Ridge Switching Station (see **Land Use Figure 1**). Neither transmission line option would present a new physical barrier within the community. Activities associated with the existing rights-of-way and installation of the transmission pole upgrades would not block existing transportation corridors and would only result in limited road delays. Arrival and departure of construction personnel and delivery of materials and supplies would occur along existing roadways and could significantly contribute to existing traffic congestion (see proposed Condition of Certification **TRANS-1** for mitigation discussed in the **TRAFFIC AND TRANSPORTATION** section of this staff assessment). Therefore, implementation of the proposed project would have a less than significant impact on community transportation or interaction and would not divide the community.

Water for a wet cooling tower, process water and other industrial uses, and for use by employees will be supplied by groundwater wells. A water treatment system would be installed to ensure that water quality meets potable standards and a sanitary septic system and onsite leach field will be used to dispose of sanitary wastewater (Ibid, pg 2.2). The 17.6-mile natural gas pipeline will exit the site to the east until reaching Neuralia Road and then turn south and proceed for nine miles until it reaches California

City Boulevard. It will then head west about five miles until reaching the SoCal Gas tie-in point adjacent to the Union Pacific Railroad line. The pipeline would be buried within the road's ROW. Because the project is consistent with the local land use designations, there will no adverse land impacts.

Kern County Zoning Ordinance Code

As displayed in the applicant's Figure 5.7-6, the proposed project site is zoned Exclusive or Limited Agriculture (A and A-1), which is consistent with the Kern County General Plan Land Use designation shown in staff's **Land Use Figure 2**. Portions of the site are in a Seismic Hazard zone and Flood Zone A. In addition, the transmission line would cross over land that is zoned Platted Lands. Title 19 of the Kern County Ordinance Code contains ordinances that deal with planning and zoning standards, requirements, and restrictions. Limited agriculture (A-1) specifically provides for resource extraction and energy development uses including solar energy electrical generators, commercial or domestic, exceeding five kilowatts capacity. Exclusive agriculture (A) and Recreation-Forestry (RF) also allows for the same solar energy use. Platted lands (PL) allows for utility and communication facilities such as a utility substation. Transmission option 2 would cross over an RF Zone area. Transmission lines are permitted in RF zoned areas. There are no height limitations except in areas of protected military airspace.

Land Use Compatibility

The project would be located within the county of Kern General Plan boundaries, in an area that supports agricultural and resource management activities (see **Land Use Figure 2**). Most of the proposed project site has a General Plan land use designation of extensive or intensive agriculture. The project is consistent with other uses currently permitted within that land use designation, provided all requirements for a conditional use permit are met. Surrounding properties are proposed primarily for agriculture and resource management.

When a jurisdictional authority, such as the county of Kern, establishes zoning districts, it is that agency's responsibility to ensure the compatibility of adjacent zoning districts and permitted uses, and incorporate conditions and restrictions that ensure those uses will not result in a significant adverse impact ("minimum of detriment") to surrounding properties. Therefore, staff assumes that permitted industrial uses or those deemed equivalent to a permitted use sited on properties zoned agricultural or resource management are compatible with surrounding uses and zoning districts. Those uses operating under a valid use permit would also be considered compatible.

The BSEP site is located within the 20,000-square-mile R-2508 military range complex and, more specifically, is under a "special use airspace" and a "low level flight path". The California Office of Planning and Research has prepared a R-2508 Joint Land Use Study that examines land use issues involved with this military range complex. Staff has reviewed a letter from the R-2508 Complex Sustainability Office that notes that the BSEP underlies several military air routes and special use airspace. However, it has been determined that the project will not have significant impacts on military activities if certain mitigation measures are implemented (NASCWP 2008). The proposed mitigation measures require the project owner to advise R-2508 officers information on planned use of the electronic spectrum (frequencies) during construction activities. In addition, the Kern County Planning Department has adopted a Military Readiness Element as part of the General Plan. This consultation is also required by Policy 1.7c of the Kern County Airport Land Use Compatibility Plan as noted in **Land Use Table 1.**

Staff's proposed Condition of Certification **LAND-2** would ensure that the project owner advise Department of Defense (DOD) representatives about the radio transmission frequencies used during the project's construction and operation. This would allow DOD representatives an opportunity to determine if project radio transmissions would interfere with military activities.

Energy Commission staff has determined that, as discussed in other sections of this document, the Beacon Solar Energy project would not result in unmitigated project-related impacts to surrounding properties. (See the **AIR QUALITY, HAZARDOUS MATERIALS, NOISE, PUBLIC HEALTH, TRAFFIC AND TRANSPORTATION,** and **VISUAL RESOURCES** sections of this document for a complete discussion of noise, dust, public health hazards or nuisance; and adverse traffic or visual impacts.)

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 [Cal. Code Regs., title 14, section 15065(a)(3)].

The applicant has identified two additional projects in the general area of the BSEP site. The first is LADWP Barren Ridge-Castaic Transmission Line Project which would begin at the Barren Ridge Switching Station about 1.5 miles south of the project site and would proceed south to Los Angeles County. The second project is the Pine Tree Wind Development which would be located six miles west of the BSEP site (BSEP 2008, pg. 5.7-12). Due to the distance from the BSEP site and the absence of significant land use impacts associated with either project or with the BSEP, cumulative impacts to existing land uses and policies would be less than significant. The Pine Tree site was previously used for grazing and/or was undeveloped land and the new transmission line would be built in an existing transmission corridor (Pine Tree 2008, LADWP 2008). No projects have been identified in the project vicinity that would create significant cumulative land use impacts when considered together with the BSEP.

CONCLUSIONS AND RECOMMENDATIONS

The Kern County General Plan allows for industrial and renewable energy development in agricultural and resource management areas. The Kern County General Plan encourages safe and orderly commercial solar development in the desert and valley planning areas. Furthermore, the Beacon Solar Energy project meets the following criterion:

- The BSEP would not physically disrupt or divide an established community or conflict with any applicable habitat conservation plan or natural community conservation plan; result in any impacts to existing agricultural operations or future use; convert farmland to non-agricultural use; or conflict with existing agricultural zoning or Williamson Act contracts.

- The proposed project is consistent with the Kern County 2007 General Plan policies the Zoning Ordinance and the project's proposed location is zoned agricultural with a geologic hazard, which is consistent with the agricultural land use designation.
- The BSEP would not have significant impacts regarding the military R-2508 Complex Sustainability operations or mission (see proposed Condition of Certification **LAND-2**; and
- Full implementation of proposed Conditions of Certification **LAND-1 & 2** would make the project consistent with applicable LORS.

Staff recommends that the Commission adopt the following conditions of certification if it approves the project.

PROPOSED CONDITIONS OF CERTIFICATION

LAND-1 The project owner shall design and construct the project in accordance with the applicable standards found in the Kern County Ordinance Code (Title 17) which includes the following:

- Building and grading codes ;
- Floodplain management and Storm Water Pollution Prevention Plan;
- Mechanical and electrical code; and
- Energy code.

Verification: At least 90 calendar days prior to the start of construction, including any grading or site remediation on the power plant project site or its associated easements, the project owner shall submit the proposed development plan to the Kern County Planning Department for review and comment and to the CPM for review and approval. The project owner shall also provide the CPM with a copy of the transmittal letter to the Kern County Planning Department.

At least 30 calendar days prior to the start of construction, the project owner shall provide copies of any comment letters received from the Kern County Planning Department, along with any changes to the proposed development plan, to the CPM for review and approval.

LAND-2 The project owner shall notify the Department of Defense (DOD) about the radio frequencies that would be used during the BSEP's operation. This would allow the DOD to determine if the project's use of those radio frequencies would interfere with military activities within the R-2508 Military Complex area.

Verification: At least 30 days prior to publication of the Final Staff Assessment for the Beacon Solar Energy project, the project owner shall provide DOD representatives with information about the specific radio frequencies to be used during project construction and operation. As needed, the project owner will modify the radio frequencies per DOD requirements. These modifications must be confirmed in writing from the DOD and shall be submitted to the CPM for review and approval.

REFERENCES

Beacon Solar Energy Project (BSEP) 2008a, Application for Certification. Submitted to the California Energy Commission on March 13, 2008.

Beacon Solar Energy Project (BSEP) 2008b. Volume 3 Data Adequacy Supplement. Submitted to the California Energy Commission on April 21, 2008.

Beacon Solar Energy Project (BSEP) 2008c. BSEP presentation at the California Energy Commission Informational Hearing on June 11, 2008.

California Department of Conservation (CDOC) 2008. Personal communication between Molly Penberth and James Adams, California Energy Commission, on September 22, 2008.

Kern County 2005. Kern County Ordinance Zone, Titles 17 and 19, effective February 2005.

Kern County 2006. Airport Land Use Compatibility Plan, last amended on June 13, 2006.

Kern County 2007. General Plan, effective April 12, 2007.

Kern County 2008a. Letter from the Lorelei Oviatt, Special Projects Division Chief, to Bill Pfanner, California Energy Commission, dated April 22, 2008.

Kern County 2008b. Letter from Lorelei Oviatt to Shaelyn Stratten, California Energy Commission, dated September 16, 2008.

Kern County 2009. Personal communication between Lorelei and James Adams, California Energy Commission, on January 30, 2009.

Los Angeles Department of Water and Power (LADWP) 2008. News Release- *LADWP Launches Environmental Study of Transmission Project to Access Renewable Energy in Tehachapi/Mojave Area*, dated April 7, 2008.

Naval Air Systems Command Weapons Division (NASCWD) 2008. Letter from A. M. Parisi, Complex Sustainability Officer, to Gary Palo, BSE Project Manager, dated February 19, 2008.

Pine Tree Wind Development Project 2008. Environmental Assessment/Final EIR, approved by the Kern County Board of Supervisors on July 26, 2008.

PRC 2005. Public Resources Code §25000 et seq (Division 15 - Warren-Alquist State Energy Resources Conservation and Development Act), Chapter 6 - Power Facility and Site Certification, §§25500-25543; September 2005.

R-2508 2008. R-2508 Joint Land Use Study, Executive Summary, dated April 2008.

NOISE AND VIBRATION

Erin Bright and Steve Baker

SUMMARY OF CONCLUSIONS

California Energy Commission staff concludes that the Beacon Solar Energy 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 Beacon Solar Energy Project (Beacon) 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.

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 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 Beacon. 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

[1] VdB is the common measure of vibration energy.

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. It should be noted that there are no current noise ordinances in Kern County.

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

Beacon would be constructed on a 2,012 acre site approximately 4 miles northwest of California City in eastern Kern County. The site and surrounding land are largely vacant, with the exception of the Honda Proving Center located approximately 0.8 miles to the east (BS 2008a, AFC § 2.3).

The ambient noise regime in the project vicinity consists of highway traffic, train traffic and the Honda Proving Center. The nearest sensitive noise receptor is a residence 0.3 miles southeast of the project site (BS 2008a, AFC Table 5.8-4).

[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 (BS 2008a, AFC § 5.8.2; Tables 5.8-4 and 5.8-5). The survey was conducted on December 3 and 4, 2007, and monitored existing noise levels at the following locations, shown on **Noise and Vibration Figure 1**:

1. Measuring Location 1: Near a residence located approximately 1,700 feet southeast of the project site where the project site boundary turns west. 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 desert environment.

2. Measuring Location 2: Near a residence located on the west side of SR-14 approximately 2,500 feet from the western edge of the project site. Long-term (25-hour) monitoring showed ambient noise levels higher than those at M-1 due to traffic on SR-14.

Noise Table 3 summarizes the ambient noise measurements (BS 2008a, AFC Table 5.8-4):

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]
Location 1: East Residence	39	35	33
Location 2: West Residence	55	57	23

Source: BS 2008a, AFC Table 5.8-4
[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 Beacon is expected to occur over a period of 25 months (BS 2008a, AFC § 5.8.3.2).

Compliance with LORS

Construction of an industrial facility such as a power plant is typically noisier than permissible under usual noise ordinances. In order to allow the construction of new facilities, construction noise during certain hours of the day is commonly exempt from enforcement by local ordinances. It should be noted that there are no specific LORS limiting construction noise in Kern County.

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 (BS 2008a, AFC § 5.8.3.2). Assuming peak construction activity, a maximum noise level of 75 dBA L_{dn} is estimated to occur at a distance of 50 feet from the acoustic center of the construction activity (most often the power block) and attenuate to 40 dBA L_{dn} or less at project site boundaries. Noise levels at the nearest residence, Location 1 (to the east), are thus projected to reach approximately 31 dBA L_{eq} for peak construction (BS2008a, AFC § 5.8.2.2, Figure 5.8-2; and staff calculations) compared to daytime and nighttime average ambient background noise levels there of 39 and 35 dBA L_{eq}, respectively. For lack of equivalent noise level values for construction noise data, staff assumes that construction noise for this project would be relatively constant and the 40 dBA L_{dn} estimated for construction noise would therefore equate to 34 dBA L_{eq} at site boundaries. Given this assumption, construction noise would be unnoticeable at the nearest receptor during both daytime and nighttime hours.

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)
Location 1 — Nearest residence (east)	31	39 daytime	40 daytime	+1 daytime
		35 nighttime	36 nighttime	+1 nighttime
Location 2 — Residences to west	30	55 daytime	55 daytime	+0 daytime
		57 nighttime	57 nighttime	+0 nighttime

1 Source: BS 2008a, AFC § 5.8.3.2 and staff calculations
2 Source: BS 2008a, AFC Table 5.8-4 and staff calculations of average of daytime and nighttime hours.

In the event that actual construction noise should annoy nearby residents, staff proposes Conditions of Certification **NOISE-1** and **NOISE-2**, which would establish a Notification Process to make nearby residents aware of the project, and a Noise Complaint Process that requires the applicant to resolve any problems caused by noise from the project.

Linear Facilities

Linear facilities include a new 17.6 mile natural gas pipeline extending from the project site to California City and new electrical transmission lines interconnecting to the transmission system to the west of the project site. Both the gas pipeline and the transmission lines would extend past the project site boundaries; the gas line would pass relatively close to two of the sensitive receptors (BS 2008a, AFC Figure 2.1). 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 the nearest residence (BS 2008a, AFC § 5.8.2.2; Figure 5.8-2). In order to minimize disturbance from steam blows, the steam blow piping can be equipped 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. This is still an annoying noise level; staff proposes that any high pressure steam blows be muffled with an appropriate silencer, and be performed only during restricted daytime hours (see proposed Conditions of Certification **NOISE-6** and **NOISE-8** below) in order to minimize annoyance to residents.

Alternatively, the Applicant may 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 would thus be about 43 dBA, much closer to the ambient background noise levels.

Regardless 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. This should help ensure the process is at least tolerable to residents.

Pile Driving

The applicant does not discuss whether pile driving would be necessary for construction of Beacon. If pile driving is required for construction of the project, the noise from this operation could be expected to reach 104 dBA at a distance of 50 feet. Pile driving noise would thus be projected to reach levels of 61 dBA at Location 1, the nearest residential receptor (staff calculation). Added to the existing daytime ambient level of 39 dBA L_{eq}, this would combine to produce 61 dBA, an increase of 22 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, should it occur, 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)
Location 1	61	39	61	+22
Location 2	60	55	61	+6

1 Source: BS 2008a, AFC Table 5.8-4 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 (BS 2008a, AFC § 5.8.3.2). 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 Beacon include the steam turbine generators, cooling tower, start-up boiler, and various pumps and fans (BS 2008a, AFC § 5.8.3.3; Table 5.8-8). 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.

The applicant included the following noise mitigation measures in performing computer modeling of noise impacts from project operation (BS 2008a, AFC § 5.8.3.3; Table 5.8-8):

- metal acoustical steam turbine enclosure; and
- 25-foot high solar mirror arrays surrounding the power block.

Compliance with LORS

The applicant performed noise modeling to determine the project's noise impacts on sensitive receptors (BS 2008a, AFC § 5.8.3.3). Project operating noise levels are expected to attenuate to less than 40 dBA L_{dn} before reaching project site boundaries. This figure complies with the noise level limits specified in the Kern County General Plan Noise Element; see **Noise Table 6**.

Noise Table 6
Plant Operating Noise LORS Compliance

Receptor	LORS	LORS Limit	Projected Noise Level
Location 1 (closest residence)	Kern County General Plan Noise Element	65 dBA L_{dn} daytime 45 dBA L_{dn} nighttime	40 dBA L_{dn}

Source: Kern County 2007 and BS 2008a, AFC § 5.8.3.3.

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.

In many cases, a power plant will be intended to operate around the clock for much of the year. As a solar thermal generating facility, Beacon would operate only during the daytime hours, typically 15 hours per day during the summer (with fewer hours during the fall, winter, and spring), when sufficient solar insolation is available. Nighttime operation would be limited to the auxiliary boilers for the steam seal system of the steam turbine (BS 2008a, AFC § 2.5.2).

Typically, daytime ambient noise consists of both intermittent and constant noises. The noise that stands out during this time is best represented by the average noise level, or L_{eq}. Staff's evaluation of the above noise surveys shows that the daytime noise environment in the Beacon project area consists of both intermittent and constant noises. Thus, staff compares the project's daytime noise levels to the daytime ambient L_{eq} levels at the project's noise-sensitive receptors.

As seen in **Noise Table** 7, power plant noise levels are predicted to be less than 40 dBA L_{dn} (34 dBA L_{eq}) at all sensitive receptors during daytime operation and less than 22 dBA L_{max} at night.

Noise Table 7
Power Plant Noise Impacts at Nearest Sensitive Receptor

Location 1 (East Residence)	Power Plant Noise Level, dBA L_{eq} [1]	Ambient Noise Level, dBA	Cumulative Noise Level, dBA	Change from Ambient Level dBA
Daytime	31	39 L_{eq} [2]	40	+1
Nighttime	21	33 L_{90} [3]	33	+0

[1] Source: BS 2008a, AFC § 5.8.3.3, Table 5.8-8 and staff calculations.
[2] Source: BS 2008a, AFC Table 5.8-4 and staff calculations of average of fifteen consecutive daytime hours.
[3] Source: BS 2008a, AFC Table 5.8-4 and staff calculations of average of four quietest consecutive nighttime hours.

When projected plant noise is added to the daytime ambient value (as calculated by staff), the cumulative level is higher than the ambient value at Location 1 by an inaudible amount (see **NOISE Table 7**). No change in ambient noise at Location 1 at night would result from plant operation.

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 to 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

All gas 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 (BS 2008a, AFC § 5.8.3.3).

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 Beacon project consist of a high-speed steam turbine generator 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 Beacon 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 Beacon 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 (BS 2008a, AFC § 5.8.3.3). 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 two projects in the vicinity of Beacon, the Pine Tree Wind Development and the Barren Ridge-Castaic Transmission Project. Due to their distance from Beacon, neither project poses a potential for cumulative noise impacts (BS 2008a, AFC § 5.8.3.4).

FACILITY CLOSURE

In the future, upon closure of Beacon, all operational noise from the project would cease, and no further adverse noise impacts from operation of Beacon 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

Construction of Beacon could create significant noise impacts on nearby sensitive noise receptors if steam blows are not adequately mitigated. Consequently, staff recommends that silencing equipment for steam blow piping be employed in the construction of the facility. Staff proposes conditions of certification to ensure this (below). Beacon, if built and operated in conformance with these proposed conditions of certification, would comply with all applicable noise and vibration LORS for both operation and construction and would produce no significant adverse noise impacts on people within the affected area, 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-half 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 Beacon, 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 Within 30 days of the project first achieving a sustained output of 80 percent or greater of rated capacity, the project owner shall conduct a 25-hour community noise survey, utilizing the same monitoring sites employed in the pre-project ambient noise survey as a minimum. The survey shall also include the octave band pressure levels to ensure that no new pure-tone noise components have been introduced. No single piece of equipment shall be allowed to stand out as a source of noise that draws legitimate complaints. Steam relief valves shall be adequately muffled to preclude noise that draws legitimate complaints. If the results from the survey indicate that the project noise levels are in excess of 34 dBA L_{eq} at the residence east of the project site, additional mitigation measures shall be implemented to reduce noise to a level of compliance with this limit.

Verification: Within 30 days after completing the survey, the project owner shall submit a summary report of the survey to the CPM. Included in the report will be a description of any additional mitigation measures necessary to achieve compliance with the above listed noise limits, and a schedule, subject to CPM approval, for implementing these measures. Within 30 days of completion of installation of these measures, the project owner shall submit to the CPM a summary report of a new noise survey, performed as described above and showing compliance with this condition.

NOISE-5 Following the project's first achieving a sustained output of 80 percent 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 equip steam blow piping with a temporary silencer that quiets the noise of steam blows to 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.
comply with the applicable California and federal regulations.

Verification: At least 15 days prior to the first high-pressure steam blow, the project owner shall submit to the CPM drawings or other information describing the temporary steam blow silencer and 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:

Pile driving and high-pressure steam blows:	8 a.m. to 5 p.m.
Other noisy work	7 a.m. to 10 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

Beacon Solar Energy Project (08-AFC-2)
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.

BS 2008a - FPL Energy/M. O'Sullivan (tn 45646). Application for Certification, dated 03/13/08. Submitted to CEC/Docket Unit on 03/14/08.

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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

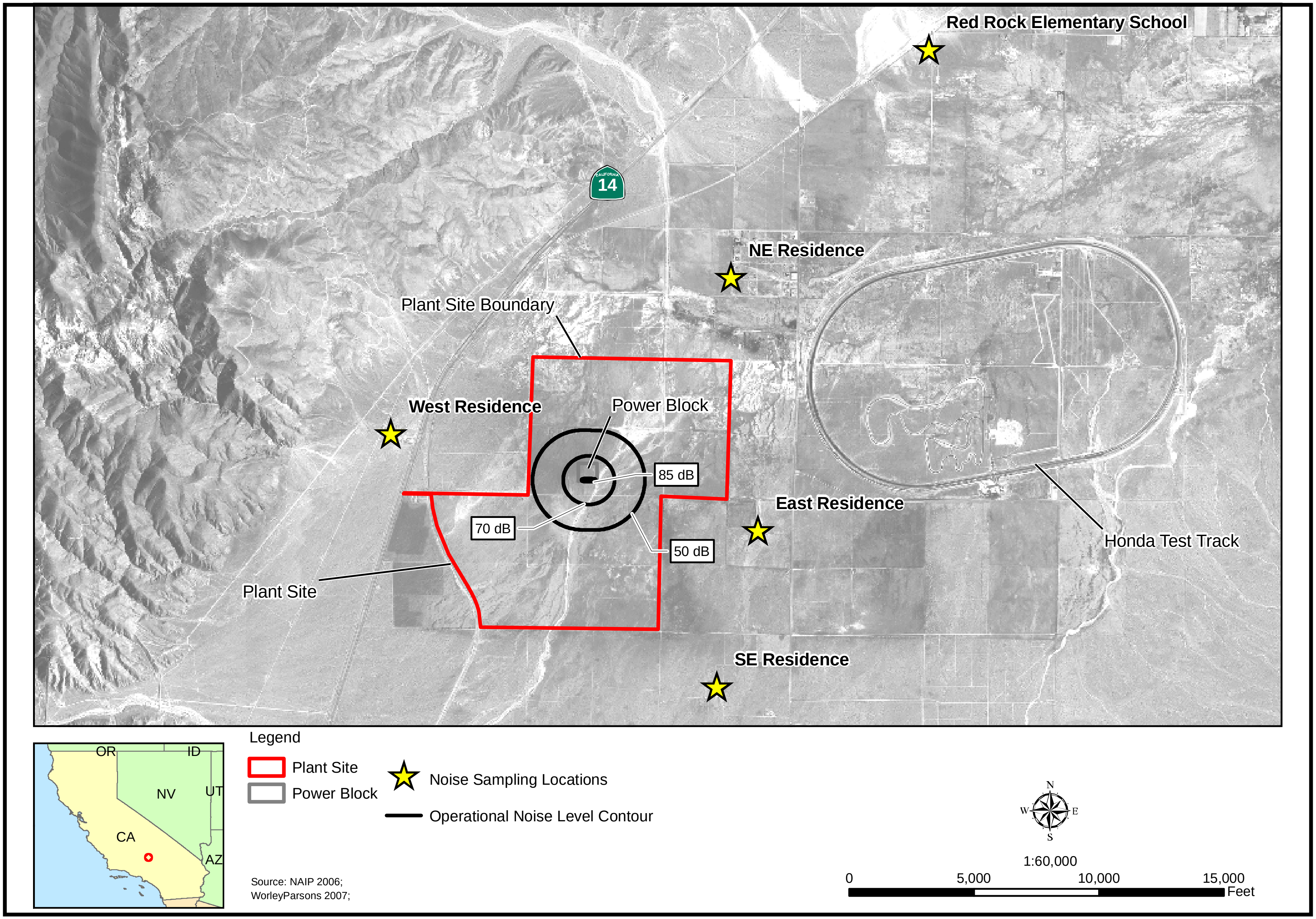
OSHA noise regulations are designed to protect workers against the effects of noise exposure and list permissible noise level exposure as a function of the amount of time to which the worker is exposed, as shown in **NOISE Table A4**.

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.

NOISE AND VIBRATION - FIGURE 1
Beacon Solar Energy Project - Operational Noise Contour Map -(Off-Site Receptors)



Source: NAIP 2006;
WorleyParsons 2007;

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMETAL PROTECTION DIVISION, APRIL 2009
SOURCE: 08-AFC-2 Figure 5.8-2

PUBLIC HEALTH

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SUMMARY AND CONCLUSIONS

Staff has analyzed the applicant's method to evaluate the potential for public health risks from the toxic air pollutants associated with construction and operation of the proposed Beacon Solar Energy Project (BSEP) and does not expect there to be any significant cancer or short- or long-term noncancer health effects requiring further mitigation than proposed by the applicant, Beacon Solar, LLC (Beacon Solar). However, staff will work with the applicant to conduct a complete health risk assessment using the Hotspots Analysis and Reporting Program (HARP) tool for inclusion in the Final Staff Assessment. Staff believes that BSEP, along with the numerous other solar projects under review deserve the same level of review as biomass and natural gas-fired generation projects to ensure consistency and comparison of potential impacts, if appropriate.

The toxic (*noncriteria)* pollutants considered in this analysis are pollutants for which there are no established air quality standards. If the proposed project is approved, staff would recommend the condition of certification **Public Health-1** to address the risk from Legionella in the cooling tower. The potential for significant public health impacts from emissions of other groups of pollutants for which there are specific air quality standards (*criteria pollutants*) is addressed in the **Air Quality** section of this report.

INTRODUCTION

The purpose of this **Public Health** analysis is to determine if toxic emissions from the proposed Beacon Solar Energy Project could produce significant adverse public health impacts or violate standards for public health protection in the project area thereby requiring mitigation beyond what the applicant (Beacon Solar) proposes. BSEP is proposed to use solar thermal technology to provide almost 100 percent of the input to the electric generation power block. The project therefore, belongs in a category of energy facilities with a renewable energy source (the sun) with minimal associated combustion by-products. The only non-solar energy source would be the two auxiliary boilers that would use natural gas to produce the energy needed to reduce startup times and also maintain the temperature of the facility's solar heat transfer fluid (Therminol) above its relatively high freezing point of 54°F. The combustion-related pollutants would thus be produced in much smaller amounts than from using natural gas for all the generated electricity. The project also includes a wet cooling tower and a diesel-fired fire pump engine.

Toxic pollutants are pollutants for which there are no specific air quality standards and are known as *noncriteria pollutants*. The other pollutants for which there are specific air quality standards are known as *criteria pollutants*. If significant health impacts are identified as possible from exposure to the noncriteria pollutants considered in this analysis, staff would evaluate the need for the more refined analysis necessary to identify further mitigation measures to reduce those impacts to less-than-significant levels.

Although compliance with air quality standards is addressed in the **Air Quality** section for the criteria pollutants, staff has included **Attachment A** at the end of this **Public Health** section to provide specific information on the nature of the health effects of these criteria pollutants. The related **Air Quality** discussion mainly focuses on the potential for exposure at levels above ambient air quality standards and the regulatory measures to mitigate that exposure, with particular emphasis on ozone and particulate matter where area levels exceed their respective air quality standards. Staff considers it necessary to mitigate the impacts of both criteria and noncriteria pollutants to ensure overall public health protection while any project is operating. The impacts on public and worker health from accidental releases of hazardous materials are examined in the **Hazardous Materials Management** section, while the health and nuisance effects from electric and magnetic fields are addressed in the **Transmission Line Safety and Nuisance** section. Pollutants released from the project in wastewater streams are discussed in the **Soils and Water Resources** section. Facility releases in the form of hazardous and non-hazardous wastes are addressed in the **Waste Management** section.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

Public Health Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
Clean Air Act section 112 (42 U.S. Code section 7412)	Requires new sources which 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 (MACT).
State	
California Health and Safety Code sections 39650 et seq.	These sections mandate the California Air Resources Board (CARB) and the Department of Health Services to establish safe exposure limits for toxic air pollutants and identify pertinent best available control technologies (BACT). They also require that the new source review rule for each air pollution control district include regulations that require new or modified procedures for controlling the emission of toxic air contaminants.
Title 17 California Code of regulations (CCR), Section 93115, Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines	Establishes emission limits and operating limits on stationary compression ignition engines, including emergency fire pump engines
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."
Local	
Kern County Air Pollution Control District (KCAPCD) Rule 210.9.	Requires safe exposure limits for Toxic Air Pollutants (TACs), use of best available control technology, new source review (NSR), and implements the state's Airborne Toxic Measure (ACTM) for Stationary Compression Ignition Engines including emergency fire pump engines as required by Title 17 CCR.

ASSESSMENT OF IMPACTS

This section describes the method used by staff and the applicant to assess the potential for health impacts from toxic pollutants from a source such as BSEP and the need for mitigation beyond the measures proposed by the applicant.

METHOD OF ANALYSIS

The toxic emissions addressed in this **Public Health** section are those to which the public could be exposed during both project construction and routine operation. If these toxic contaminants are released into the air or water, individuals may come into contact with them through inhalation, dermal contact, or ingestion via contaminated food or water.

Ambient air quality standards for the criteria pollutants such as ozone, carbon monoxide, sulfur dioxide, or nitrogen dioxide ensure the safety of everyone, including those with heightened sensitivity to the effects of environmental pollution. Since noncriteria pollutants do not have such standards, a process known as a health risk assessment (HRA) is typically used to evaluate the potential for public exposure to unhealthy levels and establish the degree of mitigation necessary. A typical risk assessment procedure consists of the following steps:

- Identification of the types and amounts of hazardous substances that a source could release to the environment;
- Estimation of worst-case concentrations of project emissions in the environment;
- Estimation of the amounts of pollutants to which humans could be exposed through inhalation, ingestion, and dermal contact; and
- Characterization of the potential health risks by comparing worst-case exposures to safety standards that are based on known health effects.

When noncriteria, or toxic substances are found in emissions, a screening-level analysis could be conducted to (a) obtain a numerical estimate of the potential cancer or noncancer risk or (b) assign a priority score to the facility to assess the need for more refined analysis and additional mitigation measures. The priority assignment method used by the applicant uses facility-related parameters (emission rates, pollutant potency, and proximity to potentially exposed human) that conservatively assume that the pollutant is not diluted after release, while the staff recommended HRA process using the HARP model would use the same emission and toxicity factors but attempts to refine potential exposure levels and locations by specifically meteorological conditions in determining the rates of dilution and exposure levels.

A screening-level risk assessment could initially be performed using simplified assumptions intentionally biased toward protecting public health. In other words, the analysis would be designed to overestimate the public health impacts from exposure to emissions. Therefore, in reality, it is likely that the actual risks from the project would be much lower than the risks estimated by the screening-level assessment. A screening-level impact assessment would at a minimum, include the potential health effects of inhaling hazardous substances. Some facilities may also emit certain substances that could present a health hazard from non-inhalation pathways such as soil ingestion, dermal exposure, and mother’s milk (see California Air Pollution Control Officers Association, CAPCOA 1990 and 1993).

This overestimation is generated by identifying conditions that could lead to the highest or worst-case risks, and then assuming those conditions in the study. The process involves the following:

- Using the highest levels of pollutants that could be emitted from the source;
- Assuming weather conditions that would lead to the maximum ambient concentration of pollutants;
- Using the type of air quality computer models that predict the greatest plausible impacts;
- Calculating health risks at the location where the pollutant concentrations are estimated to be highest;
- Using health-based standards designed to protect the most sensitive members of the population - including the young, elderly, and those with respiratory illnesses; and
- Assuming that an individual's exposure to cancer-causing agents would occur over a 70-year lifetime

These impact assessment processes address three categories of health impacts: acute (short-term) health effects, chronic (long-term) health effects, and cancer risk (also long-term). Acute health effects result from short-term (one-hour) exposure to relatively high concentrations of pollutants. These effects are temporary in nature, and include symptoms such as irritation of the eyes, skin, and respiratory tract. Chronic health effects result from long-term exposure to lower concentrations of pollutants. This exposure period is defined as being from approximately 10 to 100 percent of a lifetime (from 7 to 70 years). Chronic health effects include reduced lung function and heart disease.

The analysis for noncancer health effects includes comparison of maximum project contaminant exposure levels to safe levels called *reference exposure levels* (RELs). These are amounts of toxic substances to which even sensitive people could be exposed without suffering adverse health effects (CAPCOA 1993, p. III-36). This means that exposure limits serve to protect even sensitive individuals including infants, children, the aged, and people suffering from illnesses or diseases that make them more susceptible to the effects of toxic substance exposure. The RELs are based on the most sensitive adverse health effects reported in the medical and toxicological literature, and include specific margins of safety that address the uncertainties associated with inconclusive scientific and technical information available at the time standards were set. Margins of safety provide a reasonable degree of protection against hazards that research has yet to identify. Each margin of safety is designed to prevent pollution levels demonstrated to be harmful, as well as to prevent lower pollutant exposure that may pose an unacceptable risk of harm, even when the risk is not precisely identified by nature or degree. Health protection can be expected if the estimated worst-case exposure is below the relevant REL. In such a case, an adequate margin of safety would be assumed to exist between the predicted exposure and the estimated threshold of 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 conformance with CAPCOA guidelines, the health risk and facility prioritization assessments assume that the effects of the individual substances are additive for a given organ system (CAPCOA 1993, p. III-37). In cases where the actions could be synergistic (that is where the effects are greater than the sum), this approach may underestimate the health impact in question. Where the action is antagonistic, the approach may overestimate the impacts

For carcinogenic substances, the health assessment estimates the risk of developing cancer and conservatively includes the assumption that the individual would be continuously exposed re over a 70-year lifetime. The calculated risk is not necessarily meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound estimate based on worst-case assumptions.

Cancer risk is expressed in chances per million of developing cancer, and is a function of the maximum expected pollutant concentration, the probability that a particular pollutant will cause cancer (known as its *potency factor* and established by the California Office of Environmental Health Hazard Assessment, OEHHA), and the length of the exposure period. Cancer risks for individual carcinogens are added together to yield the total cancer risk from the source being considered. The conservative nature of these screening assumptions means that actual cancer risks would likely to be considerably lower than their estimates.

In the HRA process, the cancer and noncancer risk estimates are compared against specific significance thresholds to assess the need for and extent of further mitigation. For the facility prioritization procedure, the potential for significant impacts is calculated using the same toxicity factors and emission rates but the result is expressed as specific facility scores that describe the source as high priority, intermediate priority, or low priority also established by comparison with specific significance thresholds. For KCAPCD and other air districts, high priority sources require an HRA to assess the risk to the community, those of intermediate priority are regarded as tracking facilities which are then required to submit complete toxics inventory as specified time intervals. Facilities ranked as low priority are exempt from reporting and further mitigation because of the low potential for impacts of potential significance.

SIGNIFICANCE CRITERIA

California Energy Commission staff (Energy Commission) generally assesses the health effects of exposure to toxic emissions by first considering their impacts on the maximally exposed individual (MEI). This individual is a person who is hypothetically exposed to project emissions at a location where the highest ambient impacts were calculated using worst-case assumptions, as described above. If the potential risk to this individual is below established levels of significance, staff would consider the potential risk to be less than significant anywhere else in the project area. The priority method calculates impacts at the nearest identified sensitive receptor, not a hypothetical MEI. As described earlier, noncriteria pollutants are evaluated for short-term (acute) and long-term (chronic) noncancer health effects, as well as for cancer (long-term) health effects. The potential significance of project-related health impacts is determined separately for each of the three categories of health effects.

Acute and Chronic Noncancer Health Effects

For the HRA process, staff and the state's air pollution control districts (air districts) assesses the significance of noncancer health effects by calculating a *hazard index* for the exposure being considered. A hazard index is a ratio obtained by comparing the exposure from facility emissions to the reference (safe) exposure level for a specific toxicant. A ratio of less than 1 signifies a worst-case exposure below the safe level. The hazard indices for all toxic substances with the same types of health effects are then added together to yield a total hazard index for the source being evaluated. This total hazard index is calculated separately for acute and chronic effects. A total hazard index of less than 1 indicates that the cumulative worst-case exposure would be within safe levels. Under these conditions, health protection would be assumed even for sensitive members of the population. In that case, staff would assume that there would be no significant noncancer public health impacts from project operations.

For the facility prioritization procedure, staff and the air districts utilize the same emission rates (without dispersion modeling) together with the applicable RELS or toxicity factors, and proximity to human receptors, to calculate a total facility score for noncancer effects.

Cancer Risk

Staff relies upon the regulations developed to implement provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986 (Health & Safety Code, §§ 25249.5 et seq.) for guidance in establishing the level of significance for cancer risks. Title 22, California Code of Regulations, section 12703(b) states that "the toxic exposure which represents no significant health hazard shall be one calculated to result in one excess case of cancer in an exposed population of 100,000, assuming lifetime exposure." This hazard reflects a cancer risk of 10 in 1,000,000, which is often written as $10x10^{-6}$. An important distinction from the provisions in Proposition 65 is that its significance level applies separately to each cancer-causing substance, while staff determines significance based on the total risk from all cancer-causing chemicals from the source in question. The manner in which the significance level is applied by staff is therefore more conservative (or health-protective) than the provisions of Proposition 65.

As noted earlier, the initial risk analysis for a project is normally performed at a screening level, which is designed to overstate actual risks. When a screening analysis shows cancer risks to be above the significance level, refined assumptions would likely result in a lower, more representative risk estimate. If facility risk, based upon refined assumptions, were to exceed the significance level of 10 in 1,000,000, staff would require appropriate measures to reduce that risk to less than significant. If, after all risk reduction measures have been considered, a refined analysis still identifies a cancer risk of greater than 10 in 1,000,000, staff would deem that risk to be significant, and would not recommend approval for the project.

For the source prioritization process, staff and the air districts utilize the same emission rates for the HRA, the applicable cancer potency values, and distance to the nearest human receptor, to obtain a carcinogenic score for the source. The carcinogenic and non-carcinogenic scores are calculated using methods that allow for direct comparison of effects as either cancer or noncancer. The following thresholds are utilized in the prioritization scheme:

Total Facility Score	Category
More than 10	High Priority
1 -10	Intermediate Priority
<1	Low Priority

SETTING

This section describes the environment in the vicinity of the proposed project site from a public health perspective. Features of the natural environment, such as meteorology and terrain, affect a project's potential to impact public health. An emission plume from a facility may affect elevated areas before lower areas because of a reduced opportunity for atmospheric mixing. Consequently, areas of elevated terrain can often experience increased pollutant impacts. Also, the types of land use near a site influence population density and therefore the number of individuals potentially exposed to a project's emissions. Additional factors affecting potential public health impacts include existing air quality and environmental site contamination.

SITE AND VICINITY DESCRIPTION

According to information from the applicant (Beacon Solar 2008, pp. 1-1, 1-2, 2-1, 5.2-13, and 5.7-10), the proposed project site is on a 2,012-acre parcel in eastern Kern County California approximately four miles north-northeast of California City's northern boundary, approximately 15 miles north of the town of Mojave, and approximately 24 miles northeast of the City of Tehachapi. The site is relatively vacant and disturbed from past agricultural activities and with several abandoned structures in a relatively small area immediately to the west. The rest of the area is essentially desert land with few scattered residences the nearest of which is 0.3 miles from the nearest plant site boundary.

The relative lack of population centers was suggested by the applicant (Beacon 2008, pp. 5.7-11 and 5.10-6) as due to the relative lack of water supplies, occasional flooding, and harshness of climate. There are no community facilities with sensitive receptors (such as schools, hospitals and play grounds) located within a three-mile radius of the site. Sensitive receptor locations are those that house sensitive individuals including the elderly, children, and individuals with respiratory diseases who, as previously noted, are usually more sensitive to the effects of environmental pollutants than the general public. In most cases these locations include schools, pre-schools, daycare centers, nursing homes, medical centers, hospitals, and colleges. The nearest developed area with a full range of community services is California City (Beacon Solar 2008, p. 5.7-10).

As noted by the applicant (Beacon Solar, 2008, p. 5.11-29), information from Census 2000 shows the area's minority population to vary from 17.4 to 40.1 % within a six-mile radius of the proposed site. The percentage of the low-income was shown to vary from 8.5% to 27.0%.

METEOROLOGY

Meteorological conditions, including wind speed, wind direction, and atmospheric stability affect the extent to which pollutants are dispersed into the 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. An emission plume from a given facility may impact elevated areas before the lower-lying areas because of reduced opportunity for atmospheric mixing. When wind speeds are low and the atmosphere is stable, dispersion is reduced and localized exposure may be increased.

As more fully discussed by the applicant (Beacon Solar 2008, pp. 5.2-13 and 5.2-13), the project area is located in the Mojave Desert which is classified as "High Desert" with characteristic climatic conditions of extreme daily temperature changes, low annual precipitation, strong seasonal winds and mostly clear skies. The temperature is hot in summer, with a maximum that exceeds 100°F degrees in July and August. Winter temperatures are more moderate with mean maxima in the 60s and low 30s. The average annual precipitation is less than six inches 78 percent of which falls between November and March. However, summer thunderstorms occur between July and September with attendant flash flooding in many areas. These climatic conditions are produced by the large-scale warming and sinking of the air in the semi-permanent subtropical high-pressure center over the Pacific Ocean. This high-pressure system helps block out most mid-latitude storms except in the winter when most of the area's rainfall occurs, as noted. The presence of a low thermal pressure above the Mojave Desert promotes air movement that transports pollutants from the Los Angeles air basin to the project area. As discussed in the **Air Quality** section, such pollution transport is largely responsible for the area's relatively high levels of ozone and particulate matter even though there generally are no local emission sources.

Atmospheric stability is a measure of the turbulence that influences pollutant dispersion. Mixing heights (the height above ground level below which the air is well mixed and in which pollutants can be effectively dispersed) are lower during the morning hours because of temperature inversions, which are followed by temperature increases in the warmer afternoons. Staff's **Air Quality** section presents a more detailed discussion of the area's meteorology as related to pollutant dispersion.

EXISTING AIR QUALITY

By examining average toxic concentration levels from representative air monitoring sites in California with cancer risk factors specific to each contaminant, a 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 American is about 1 in 3, or 330,000 in 1,000,000

As noted by the applicant (Beacon Solar 2008, p. 5.10-6), there have been no specific studies within KCAPCD to assess the health status of residents or measure the area's toxic pollutant levels. In the case of San Joaquin Valley Air Pollution Control District, an adjacent district with a relatively similar setting, the year 2000's background air toxics levels were reported as posing a background cancer risk of 225 in 1,000,000 (ARB 2002). The pollutants 1,3-butadiene, and benzene emitted primarily from mobile sources were reported as the two highest contributors to the risk and together accounted for over half of the total. The risk from 1,3-butadiene was about 73 in 1,000, 000 while the risk from benzene was 68 in 1,000,000. Formaldehyde from motor vehicles and other combustion sources accounted for about 12 % of the percent of the ambient cancer 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 in ambient levels of air toxics and associated cancer risk in California over the past few years.

The toxic pollutant-related background risk estimates can be compared with the noted normal background lifetime cancer risk (from all cancer causes) of 1 in 3, or 330,000 in 1,000,000. The potential risk from BSEP and similar sources should be assessed within the context of their potential additions to these background risk levels. As noted by the applicant (Beacon Solar 2008 p. 5.10-5), KCAPCD does not require an HRA for a facility assigned a low facility score through the facility prioritization process.

The criteria pollutant impacts for the project area are assessed in the **Air Quality** section by adding existing levels (as measured at area monitoring stations), to the project-related emissions, then comparing the results with applicable air quality standards. Protection from exposure to criteria pollutants is achieved through imposition of specific technical and administrative measures ensuring that the project does not create or contribute to violations of air quality standards when being built or operated It is this combination of measures that is addressed in the **Air Quality** section.

IMPACTS

POTENTIAL IMPACTS OF PROJECT'S NON-CRITERIA POLLUTANTS

The health impacts of BSEP's noncriteria pollutant emissions can be assessed separately for construction-phase impacts or operational-phase impacts.

Construction Phase Impacts

Possible construction-phase impacts, as noted by the applicant (Beacon Solar 2008, pp. 5.2-38 and 5.2-40, and Appendix E.2), are from human exposure to wind-blown dust from site excavation and grading, and emissions from construction equipment. These dust-related impacts may result from either exposure to the dust itself as particulate matter of less than 10 microns in diameter (PM10), particulate matter of less than 2.5 microns in diameter (PM 2.5), or exposure to any toxic contaminants that might be adsorbed on to the dust particle. As more fully discussed in the **Waste Management** section, the applicant's site contamination assessments (Beacon Solar 2008, p 5.16-10 and Appendix I) found no signs of pollutants that could constitute a health hazard to humans, meaning that construction activities would not pose significant risk to human health.

The applicant has specified the mitigation measures necessary to minimize construction-related fugitive dust as required by KCAPCD Rules 402, 404.1, 405, 407 and 409 (Beacon Solar 2008, pp. 5.2-8 and 5.2-9). The only soil-related construction impacts of potential significance would be from the possible impacts of PM10 or PM 2.5 as a criteria pollutant for the 25-month construction period. As mentioned earlier, the potential for significant impacts from criteria pollutants is assessed in the **Air Quality** section, where the requirements for mitigation measures are presented as specific conditions of certification.

The exhaust from diesel-fueled vehicular and non-vehicular equipment has been established as a potent human carcinogen. Thus, construction-related emission levels could possibly add to the carcinogenic risk in this analysis. The state's air pollution control districts have relied on the risk assessments by OEHHA in establishing specific control measures for the use of diesel-fueled equipment in construction activities. The applicant has presented the diesel emissions from the different types of equipment to be used in the construction phase together with the emission control measures required by KCAPCD for the proposed and similar projects in compliance with the noted requirements in the LORS Table (Beacon Solar 2008, p 5.2-29 and 5.2-30 and Appendix E.2). The recommended control measures specified in **Air Quality** section as conditions of certification AQ-SC1through AQ-SC5 would be adequate to reduce any exposure to levels not posing a significant cancer risk, especially in this relatively short construction period.

Operational Impacts

The emissions of most concern from routine BSEP operation would originate from its auxiliary boiler operation with limited hours of operation, limited testing of the emergency diesel firewater pump engine, the evaporative cooling tower, and the Therminol decomposition products (biphenyl and benzene) from vents for the expansion tanks. In addition to the toxic substances emitted from the cooling tower, there is specific concern that bacterial growth in the cooling tower could lead to potentially adverse human health effects. This is discussed below in the section on cooling tower operation and the risk of Legionnaires' disease.

Public Health Table 1 lists the project's toxic pollutants of potential concern and shows how each could contribute to the risk reflected by the project's priority ranking. For example, the first row shows that oral exposure to benzene is not of concern but, if inhaled, may have cancer and chronic (long-term) non-cancer health effects, as well as acute (short-term) effects.

As noted in a publication by the South Coast Air Quality Management District (SCAQMD 2000, p 6), one property that differentiates the air toxics from the criteria pollutants is their tendency to be highest in close proximity to the source and quickly drop off with distance. This means that the levels of BSEP's air toxic contaminants would be highest in the immediate area and decrease rapidly with distance. The issue of concern is the potential for significant effects at expected ambient concentrations.

Public Health Table 2
Types of Health Impacts and Exposure Routes Attributed to Toxic Emissions

Substance	Oral Cancer	Oral Non-Cancer	Inhalation Cancer	Non-cancer (Chronic)	Non-cancer (Acute)
Benzene			✔	✔	✔
Biphenyl				✔	
Chloroform			✔	✔	
Dichlorobenzene				✔	✔
Diesel Particulate Matter			✔	✔	
Formaldehyde			✔	✔	✔
Hexane				✔	
Naphthalene	✔	✔	✔	✔	
Benzo(a)pyrene		✔		✔	✔
Naphthalene				✔	
Benzofluoranthrene			✔	✔	✔
Polynuclear Aromatic Hydrocarbons (PAHs)	✔	✔	✔	✔	
Dibenzo (a, h) anthracene				✔	
Indole(1,2,3-cd) pyrene			✔	✔	✔
7, 12-Dimethyl(a) anthracene				✔	✔
Phenol				✔	✔
Toluene				✔	

Source: Prepared by staff using reference exposure levels and cancer unit risks from CAPCOA Air Toxics "Hot Spots" Program Revised 1992 Risk Assessment guidelines, October 1993, SRP 1998, Office of Environmental Health Hazard Assessment Air Toxics Hot Spots Program Risk Assessment guidelines, and Beacon Solar 2008, p. 5.10-1.

The applicant's assumption of minimal BSEP contribution to the area's carcinogenic and non-carcinogenic pollutants derives from the low facility scores calculated according to procedures specified in the previously noted 1990 CAPCOA guidelines. The results from this assessment (summarized in staff's **Public Health Table 3**) were provided to staff along with documentation of the assumptions used (Beacon Solar 2008 pp. 5.10-9 through 5.10-15 and Appendix E.2). This documentation included:

- Pollutants considered;
- Emission levels assumed for the pollutants involved;
- Exposure pathways considered;
- The carcinogenic scoring estimation process;

- The non-carcinogenic scoring process; and
- Priority ranking process.

Staff finds these assumptions to be acceptable for use in this mitigation-related analysis, and agrees with the applicant's findings with regard to the priority ranking of BESP and the need for mitigation beyond the levels the applicant proposes.

As shown in **Public Health Table 3**, the total project score for carcinogenic effects is 0.23 and 0.10 for non-carcinogenic effects. As specified in the CAPCOA guidelines, the higher of the two scores (0.23) is specified as the facility's priority score. This score is well below KCAPCD's other air district's and staff's significant threshold of 1.0 suggesting that the pollutants in question are unlikely to pose a significant risk of either chronic or acute non-cancer health effects anywhere in the project area.

Public Health Table 3
Beacon Solar Energy Project's Toxic Air Pollutant Prioritization Scores

Type of Health Impact	Priority Score	Significance Threshold	Significant?
Noncancer	0.10	1.0	No
Individual Cancer	0.23	1.0	No

Staff's summary of information from Beacon Solar 2008, pp. 5.10-6 through 5.10-14.

Cooling Tower-Related Risk of Legionnaires disease

Legionella is a bacterium that is ubiquitous in natural aquatic environments and widely distributed in man-made water systems. It is the principal cause of legionellosis, more commonly known as Legionnaires' disease, which is similar to pneumonia. Transmission to people results mainly from the 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 associated with outbreaks of legionellosis since cooling water systems and their components can amplify and disseminate aerosols that contain Legionella. The related controls include the use of chlorine or other biocides to minimize the growth of Legionella and other microorganisms.

Legionella can grow symbiotically with other bacteria and 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. Staff notes that most cooling tower water treatment programs are designed to minimize scale, corrosion, and biofouling, but not necessarily to control Legionella.

Effective mitigation measures should include a cleaning and maintenance program to minimize the accumulation of bacteria, algae, and protozoa that may contribute to the nourishment of Legionella. The American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE 1998) emphasizes the need for such programs in its specifications for Legionellosis prevention. Also, the Cooling Tower Institute has issued guidelines for the best practices for control of Legionella (CTI 2000). Preventive maintenance includes effective drift eliminators, periodically cleaning the system as appropriate, maintaining mechanical components, and maintaining an effective water treatment program with appropriate biocide concentrations.

Staff's recommended Condition of Certification **Public Health-1** is intended to ensure the effective maintenance and bactericidal action necessary during the operation of BSEP's cooling tower using underground water from the Mission Creek sub basin. This condition would specifically require the project owner to prepare and implement a cooling water management plan to ensure that bacterial growth is kept to a minimum in the cooling tower. With the use of an aggressive antibacterial program, coupled with routine monitoring and biofilm removal, the risk associated with bacterial growth and dispersal would be reduced to less than significant.

CUMULATIVE IMPACTS

As reflected in BSEP's prioritization score, its construction and operation would generate toxic pollutants at levels considered insignificant by KCAPCD, the other air districts, and staff in assessing potential compliance with applicable LORS and the need for further mitigation. This low priority score means that the project would not significantly add to the lifetime risk of cancer and noncancer risk to any individual in the project area. The applicant (Beacon 2008 p. 5.10-6) identified two future area projects that could add to the combined impacts of pollutants from BSEP and background levels. As further discussed by the applicant, these two projects (the Pine Tree Wind project and a transmission project), would be located too far from BSEP to significantly add to any pollution-related impacts from BSEP.

Given the identified lack of significant emissions from construction and operation of BSEP, staff agrees with the applicant that further mitigation would not be necessary to ensure compliance with the health and safety LORS of concern in this analysis. The relative lack of construction and operational impacts means that there would be no environmental justice concerns related to public health.

COMPLIANCE WITH LORS

The toxic pollutant-related prioritization scoring for BSEP reflect the likely effectiveness of the mitigation measures specified by the applicant to control toxic emissions from the project's main sources. The construction-related measures include the use of effective controls against particulate matter and diesel exhaust from construction activities and use of the project's fire water pump. The operations-related measures include the use of cleaner-burning natural gas and an oxidation catalyst in the auxiliary boilers, limiting the hours of operations for these boilers, and use of a non-combustion source (sun energy) for electricity generation. Since the calculated prioritization score is below the air districts' and staff's significance levels, staff concludes that the proposed construction and operational plan would complying with the health and safety LORS of concern in this analysis.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff did not receive any agency or public comments on the public health aspects of BSEP's operations.

CONCLUSIONS AND RECOMMENDATIONS

Staff has determined that the applicant's method evaluated whether toxic air emissions from the construction and operation of this proposed solar-powered are at levels that do not require mitigation beyond the specific emission control measures noted above. However, staff will work with the applicant to conduct a complete health risk assessment using the Hotspots Analysis and Reporting Program (HARP) tool for inclusion in the Final Staff Assessment. Staff believes that BSEP, along with the numerous other solar projects under review deserve the same level of review as biomass and natural gas-fired generation projects to ensure consistency and comparison of potential impacts, if appropriate.

Implementation of staff's proposed condition of certification to reduce the likelihood of Legionella or other bacterial growth would ensure that the risk of bacterial growth and dispersion is reduced to levels of insignificance. If the proposed project is approved, staff would recommend the following condition of certification to address the risk from Legionella in the cooling tower. The conditions for ensuring compliance with all applicable air quality standards are specified in the **Air Quality** section for the area's criteria pollutants.

PROPOSED CONDITION OF CERTIFICATION

Public Health-1 The project owner shall develop and implement a Cooling Water Management Plan that is consistent with either staff's *Cooling Water Management Program Guidelines* or the Cooling Technology Institute's *Best Practices for Control of Legionella* guidelines.

Verification: At least 30 days prior to the commencement of cooling tower operations, the Cooling Water Management Plan shall be provided to the Compliance Project Manager for review and approval.

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ATTACHMENT A - CRITERIA POLLUTANTS

OZONE (O_3)

Ozone is not directly emitted from specific sources but is formed when reactive organic compounds (VOCs) interact with nitrogen oxides in the presence of sunlight. Heat speeds up the reaction, typically leading to higher concentrations in the relatively hot summer months. Ozone is a colorless, reactive gas with oxidative properties that allow for tissue damage in the exposed individual. The effects of such damage could be experienced as respiratory irritation that could interfere with normal respiratory function. Ozone can also damage plants and other materials susceptible to oxidative damage.

The U.S. EPA revised its federal ozone standard on July 18, 1997 (62 Fed. Reg. 38856), based on health studies that became available since the standard was last revised in 1979. These new studies showed that adverse health effects could occur at ambient concentrations much lower than reflected in the previous standard, which was based on acute health effects experienced during heavy exercise. In proposing the new standard, the EPA identified specific health effects known to have been caused by short-term exposures (of one to three hours) and prolonged exposure (of six to eight hours) (61 Fed. Reg. 65719). However, a 1999 federal court ruling blocked implementation of the ozone 8-hour standard, which is yet to be implemented.

Acute health effects from short-term exposures include a transient reduction in pulmonary function, and transient respiratory symptoms including cough, throat irritation, chest pain, nausea, and shortness of breath with associated effects on exercise performance. Other health effects of short-term or prolonged O_3 exposures include increased airway responsiveness (which predisposes the individual to bronchoconstriction induced by external stimuli such as pollen and dust), susceptibility to respiratory infection (through impairment of lung defense mechanisms), increased hospital admissions and emergency room visits, and transient pulmonary inflammation.

Generally, groups considered especially sensitive to the effects of air pollution include persons with existing respiratory diseases, children, pregnant women, and the elderly. However, controlled exposure data on people in clinical settings have indicated that the population at greatest risk of acute effects from ozone exposures as children and adults engaged in physical exercise. Children are most at risk because they are active outside, playing and exercising, during summer when ozone levels are highest. Adults who are outdoors and engaging in heavy exertion in the summer months are also among the individuals most at risk. This happens because such exertion increases the amount of O_3 entering the airways and can cause O_3 to penetrate to peripheral regions of the lung where lung tissue is more likely to be damaged. These individuals, as well as those with respiratory illnesses such as asthma, can experience a reduction in lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during periods of moderate exertion.

CARBON MONOXIDE (CO)

Carbon monoxide is a colorless, odorless gas which is a product of inefficient combustion. It does not persist in the atmosphere, being quickly converted to carbon dioxide. However, it can reach high levels in localized areas, or "hot spots".

CO reduces the oxygen carrying capacity of the blood, thereby disrupting the delivery of oxygen to the body's organs and tissues. Persons sensitive to the effects of carbon monoxide include those whose oxygen supply or delivery is already compromised. Thus, groups potentially at risk to carbon monoxide exposure include persons with coronary artery disease, congestive heart failure, obstructive lung disease, vascular disease, and anemia, and the elderly, newborn infants, and fetuses (CARB 1989, p. 9). In particular, people with coronary artery disease were found to be especially at risk from carbon monoxide exposure (CARB 1989, p. 9). Tests conducted on patients with confirmed coronary artery disease indicated that exposure to low levels of carbon monoxide during exercise can produce significant cardiac effects. These effects include chest pain (angina) and electrocardiographic changes indicative of effects on the heart muscle (CARB 1989, p. 6). Such changes can limit the ability of patients with coronary artery disease to exert themselves even moderately. Therefore, the statewide carbon monoxide one-hour and eight-hour standards were adopted in part to prevent aggravation of chest pain. Additionally, however, the standards are intended to prevent decreased exercise tolerance in persons with peripheral vascular disease and lung disease, impaired central nervous system functions, and effects on the fetus (Cal. Code Regs. Tit. 17, sec. 70200).

PARTICULATE MATTER (PM)

Particulate matter is a generic term for particles of various substances, which occur as either liquid droplets or small solids of a wide range of sizes. Particles with the most potential to adversely affect human health are those less than 10 micrometers (millionths of a meter) in diameter (known as PM10), which may be inhaled and deposited within the deep portions of the lung (PM10). PM may originate from anthropogenic or natural sources such as stationary or mobile combustion sources or windblown dust. Particles may be emitted directly to the atmosphere or result from the physical and chemical transformation of gaseous emissions such as sulfur oxides, nitrogen oxides, and volatile organic compounds. PM10 may be made up of elements such as carbon, lead, and nickel; compounds such as nitrates, organics, and sulfates; and complex mixtures such as diesel exhaust and soil fragments. The size, chemical composition, and concentration of ambient PM10 can vary considerably from area to area and from season to season within the same area.

PM10 can be grouped into two general sizes of particles, fine and coarse, which differ in formation mechanisms, chemical composition, sources, and potential health effects. Fine-mode particles are those with a diameter of 2.5 micrometers or less (PM2.5), while the coarse-mode fraction of PM consists of particles ranging from 10 micrometers down to 2.5 micrometers in diameter.

Coarse-mode PM10 is formed by crushing, grinding, and abrasion of surfaces, and in the course of reducing large pieces of materials to smaller pieces. Coarse particles consist mainly of soil dust containing oxides of silicon, aluminum, calcium, and iron; as well as fly ash, particles from tires, pollen, spores, and plant and insect fragments. Coarse particles normally have shorter lifetimes (minutes to hours) and only travel over short distances (of less than tens of kilometers). They tend to be unevenly distributed across urban areas and have more localized effects than the finer particles.

PM2.5 is derived both from combustion by-products, which have volatilized and condensed to form primary PM2.5, and from precursor gases reacting in the atmosphere to form secondary PM2.5. Components include nitrates, organic compounds, sulfates, ammonium compounds, and trace elements (including metals) as well as elemental carbon such as soot. Major sources of PM2.5 are fossil fuel combustion by electric utilities, industry and motor vehicles, vegetation burning, and the smelting or other processing of metals. Dry deposition of fine mode particles is slow allowing such particles to often exist for long periods of time (from days to weeks) in the atmosphere and travel hundreds to thousands of kilometers. They tend to be uniformly distributed over urban areas and larger regions and are removed from the atmosphere primarily by forming cloud droplets and falling out within raindrops.

The health effects of PM10 from any given source usually depend on the toxicity of its constituent pollutants. The size of the inhaled material usually determines where it is deposited in the respiratory system. Coarse particles are deposited most readily in the nose and throat area while the finer particles are more likely to be deposited within the bronchial tubes and air sacs, with the greatest percentage deposited in the air sacs. Until recently, PM10 particles had been considered to be the major fraction of airborne particulates responsible for various adverse health effects. The PM10 fraction is known to be capable of penetrating the thoracic and alveolar regions of the human and animal lungs. The PM2.5 fraction, however, was found to pose a significantly higher risk for health. This is due to their size and associated deposition and retention characteristics in the respiratory tract, enabling it to penetrate and deposit within the deeper alveolar regions of the lung. The following aspects of PM2.5 deposition all contribute to the more serious health effects attributed to smaller particles:

- The deposition of PM2.5 favors the periphery of the lungs, which is especially vulnerable to injury for anatomical reasons.
- Clearance of the PM2.5 from within the deeper reaches of the lungs is a much slower process than from the upper regions. Consequently, the residence time is longer, implying longer exposure, and hence greater risk.
- The human anatomy further allows the penetration of the superficial tissues by PM2.5 and entry into the bodily circulation without much effort in the periphery of the lungs.

Many epidemiological studies have shown exposure to particulate matter capable of inducing a variety of health effects, including premature death, aggravation of respiratory and cardiovascular disease, changes in lung function and increases in existing respiratory symptoms, effects on lung tissue structure, and impacts on the body’s respiratory defense mechanisms. The underlying biological mechanisms are still poorly understood. Based on their review of a number of these epidemiological studies (as published after 1987 when the federal standards were revised), together with suggestion of PM2.5 concentrations as a more reliable surrogate for the health impacts of the finer fraction of PM than PM10, the U.S. EPA concluded that the then-current standards were not sufficiently stringent to protect against significant effects in exposed humans. Therefore, federal PM standards were revised on July 18, 1997 (62 Fed. Reg. 38652) to add new annual and 24-hour PM2.5 standards to the existing annual and 24-hour PM10 standards. Taken together, these new standards were meant to provide additional protection against a wide range of PM-related health effects, including premature death, increased hospital admissions and emergency room visits, primarily among sensitive individuals such as the elderly, children and individuals with cardiopulmonary diseases such as asthma. Other impacts include decreased lung function (particularly in children and asthmatics) and alterations in lung tissue and structure.

California has also had 24-hour and annual standards for PM10 (CARB 1982, pp. 81, 84). These standards were set to protect against asthma, premature death and bronchitis-related symptoms within the general population as well as sensitive individuals such as patients with respiratory disease, declines in pulmonary function, especially as related to children (Tit. 17, Cal. Code Regs. §70200). These standards were set to be more stringent than the federal standard, which the CARB regarded as inadequate for the protection desired (CARB 1991, p. 26).

On June 20, 2002, the CARB approved the adoption of a lower annual state standard for PM10, as well as a new annual standard for PM2.5 (CARB 2002). The new standards took effect on July 5, 2003. The 24-hour PM10 standard was not changed. The standards were established to prevent excess death, illnesses such as respiratory symptoms, bronchitis, asthma exacerbation, and cardiac disease, and restrictions in activity from short- and long-term exposures (Title 17, Cal. Code Regs. §70200).

NITROGEN DIOXIDE (NO_2)

Nitrogen dioxide is formed either directly or indirectly when oxygen and nitrogen in the air combine together during the combustion. It is a relatively insoluble gas, which can penetrate deep into the lungs, its principal site of toxicity. Its toxicity is thought to be due to its capacity to initiate free radical-mediated reactions while oxidizing cellular proteins and other biomolecules (CARB 1992, Appendix A, p. 4).

Sub lethal exposures in animals usually produce inflammations and varying degrees of tissue injury characteristic of oxidant damage (Evans in CARB 1992, Appendix A, and p 5). The changes produced by low-level acute or sub chronic exposures appear to be reversible when the animal study subject is allowed to recover in clean air. Health effects of particular concern in relation to low-level nitrogen dioxide exposure include: (1) effects of acute exposure on some asthmatics and possibly on some persons with chronic bronchitis, (2) effects on respiratory tract defenses against infection, (3) effects on the immune system, (4) initiation or facilitation of the development of chronic lung disease, and (5) interaction with other pollutants (CARB 1992, Appendix A, p. 5).

Several groups, which may be especially susceptible to nitrogen dioxide-related health effects have been identified from human studies (CARB 1992, Appendix A, and p. 3). These include asthmatics, persons with chronic bronchitis, infants and young children, cystic fibrosis and cancer patients, people with immune deficiencies, and the elderly.

Studies involving brief, controlled exposures on sensitive individuals have shown an increase in bronchial reactivity or airway responsiveness of some asthmatics, as well as decreased lung function in some patients with chronic obstructive lung disease (CARB 1992, Appendix A, p. 2). In general, bronchial hyper reactivity (an increased tendency of the airways to constrict) is markedly greater in asthmatics than in non-asthmatics upon exposure to initiating respiratory irritants (CARB 1992a, p. 107). At exposure concentrations of specific relevance to the current one-hour ambient standard, there appears to be little, if any, effect on respiratory symptoms of asthmatics (CARB 1992a, p. 108).

SULFUR DIOXIDE (SO_2)

Sulfur dioxide is formed when any sulfur-containing fuel is burned. SO_2 is highly soluble and consequently absorbed in the moist passages of the upper respiratory system. Exposure to sulfur dioxide can lead to changes in lung cell structure and function that adversely affect a major lung defense mechanism known as mucociliary transport. This mechanism functions by trapping particles in mucus in the lung and sweeping them out via the cilia (fine hair-like structures) also in the lung. Slowed mucociliary transport is frequently associated with chronic bronchitis.

Exposure to sulfur dioxide can produce both short- and long-term health effects. Therefore, California has established sulfur dioxide standards to reflect both short- and long-term exposure concerns. Based on controlled exposure studies of human volunteers, investigators have found that asthmatics comprise the group most susceptible to adverse health effects from exposure to sulfur dioxide (CARB 1994, p. V-1).

The primary short-term effect is bronchoconstriction, a narrowing of the airways, which results in labored breathing, wheezing, and coughing. The short-term (one-hour) standard is based on bronchoconstriction and associated symptoms (such as wheezing and shortness of breath) in asthmatics and is designed to protect against adverse effects from five to ten minute exposures. In the opinion of the California Office of Environmental Health Hazard Assessment, the short-term ambient standard is likely to afford adequate protection to asthmatics engaged in short periods of vigorous activity (CARB 1994, Appendix A, p. 16).

Longer-term exposure is associated with increased incidence of respiratory symptoms (such as coughing and wheezing) or respiratory disease, decreases in pulmonary function, and an increased risk of premature mortality (CARB 1991a, p. 12). The long-term (24-hour) standard is based upon increased incidence of respiratory disease and premature mortality. The standard includes a margin of safety based on epidemiological studies, which have shown adverse respiratory effects at levels slightly above the standard. Some of the studies indicate a sulfur dioxide threshold for effects, suggesting that no significant effects are expected from exposures to concentrations at the state standard (Ibid.).

ATTACHMENT A - REFERENCES

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SOCIOECONOMICS

Marie McLean

SUMMARY OF CONCLUSIONS

Staff found either no impacts or less than significant environmental impacts from the construction and operation of the Beacon Solar Energy Project (BSEP), a 250 MW solar facility to be constructed in Kern County. See **Socioeconomics Table 2**, CEQA Environmental Checklist Form.

Staff identified the following economic benefits from the project: capital costs; construction and operation payroll; property and sales taxes; and school impact fees.

INTRODUCTION

In this analysis California Energy Commission (Energy Commission) staff presents its analysis of the estimated impacts and benefits resulting from the construction and operation of the BSEP. In addition, staff provides information about the Energy Commission's demographic screening (environmental justice) procedures related to this project.

In preparing its analysis, staff evaluated changes to public services and infrastructure according to *California Environmental Quality Act, Appendix G,* "Environmental Checklist Form: Population and Housing; Public Services; and Recreation." See "Assessment of Impacts," in this document. Staff also evaluated project-induced fiscal changes as reported by the applicant. See "Noteworthy Public Benefits," in this document.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

SOCIOECONOMICS Table 1 contains all applicable socioeconomics laws, ordinances, regulations, and standards (LORS) applicable to the proposed BSEP.

Socioeconomics, Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

California Education Code, Section 17620	Authorizes the governing board of any school district 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 65995–65997	Authorizes school districts to levy fees against development projects according to *Education Code* 17620. Conversely, public agencies at the state and local level may not impose fees, charges, or other financial requirements to offset the cost for school facilities except for those fees established according to *Education Code* 17620.
California Revenue and Taxation Code Section 70-74.7	Currently, property taxes are not assessed on solar components. That law will be in effect until January 1, 2010 (2008-2009 property tax lien) unless extended by the California Legislature.

SETTING

PROJECT LOCATION

The Beacon Solar Energy Project (BSEP), a 250 MW solar facility, is located approximately four miles north-northwest of California City's northern boundary; 15 miles north of Mojave; and 24 miles northeast of Tehachapi. Koehn Lake is located approximately five miles to the east; Red Rock Canyon State Park, approximately four miles north. An automotive test track facility, Honda Proving Center, is located about 0.8 miles to the east. Kern County is bordered on the north by Kings County, Tulare County, and Inyo County; south by Los Angeles County; west by San Bernardino County; and east by San Luis Obispo County. Kern County consists of approximately 222 cities, towns, and US Census-designated places, including the following eleven incorporated cities: Arvin, Bakersfield, California City, Delano, Maricopa, McFarland, Ridgecrest, Shafter, Taft, Tehachapi, and Wasco. Construction is scheduled to begin in third quarter, 2009, with a project completion and operational date in third quarter 2011. The project's life is estimated to be 20 years.

DEMOGRAPHIC SCREENING

Staff's demographic screening analysis is designed to determine the existence of a minority or below-poverty-level population or both within a six-mile area of the proposed project site.

The demographic screen process is conducted based on information contained in two documents: *Environmental Justice: Guidance Under the National Environmental Policy Act* (Council on Environmental Quality, December 1997) and *Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analysis* (Environmental Protection Agency, April 1998). 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.

Minority population concentrations occur when the minority population of the potentially affected area is (1) greater than 50 percent; (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 of more U.S. Census blocks in the potentially affected area have a minority population of greater than 50 percent.

For the Beacon Solar Energy Project, the total population within the six-mile radius of the propoised site is 256 persons; and the total minority population is 45 persons or 17.57 percent of the total population within a six-mile radius of the site (See **Socioeconomics Figure 1**.) However, within this six-mile radius, U.S. Census blocks with populations of greater than 50 percent exist. Consequently, staff in several technical areas indentified in the Executive Summary, including Socioeconomics, have considered environmental just in their environmental impact analyses.

Below-Poverty-Level Populations

Staff has also identified within a six-mile radius of the project current below-poverty-level populations based on Year 2000 U. S. Census block group data. The below-poverty-level population within a six-mile radius of the Beacon Solar Energy project consists of 779 people or 19.46 percent of the total population in that area.

ASSESSMENT OF IMPACTS

This section includes information about the following:

1. Method and threshold for determining significance
2. Direct/indirect/induced impacts and mitigation
3. Cumulative impacts and mitigation

Method and Threshold for Determining Significance

Socioeconomics is concerned with population, housing, public services, recreation, and finance and the impacts they have people's daily lives. To determine a project's potentially significant environmental impacts as they relate to socioeconomics, Energy

Commission staff reviews the project according to “Guidelines for the Implementation of the California Environmental Quality Act; Appendix G, “Environmental Checklist Form, Population and Housing; Public Services; and Recreation.”

As required by the guidelines, staff determines a project’s potentially significant impact on population and housing, public services, and recreation by evaluating the impact of the project on those three areas. See **Socioeconomics Table 2**, CEQA Environmental Checklist Form.

To conduct this evaluation and arrive at the conclusions contained **Socioeconomics Table 2**, staff analyzed the current status of population, housing, public services, and recreation to determine if project-related impacts would significantly strain or degrade those services. In addition, staff:

1. Reviewed the BSEP Application for Certification (AFC)

2. Researched, collected, and analyzed socioeconomic data from various governmental agencies, trade associations, and public interest research groups.

As indicated in **Socioeconomics Table 2**, staff found the project to have no impact on population and housing; less than significant impact on fire and police protection; no impact on schools, parks, and other public facilities; and no impact on recreation. If staff had found the project to have a significant effect on population and housing, public services, or recreation, staff would propose mitigation.

Conversely, the project could have beneficial fiscal and nonfiscal effects on the project area. For example, property taxes, sales taxes, or local school impact or development fees resulting from the construction and operation of the project could help local governments augment needed public services. Consequently, in this socioeconomic analysis, staff:

1. Examined the beneficial impacts on local finances from property and sales taxes and other sources of revenue.

2. Included information about the project’s economic benefits in this section. See **Socioeconomics Table 5**, “Noteworthy Public Benefits Related to Beacon Solar Energy Project,” at the end of this document.

Direct/Indirect/Induced Impacts and Mitigation

Information about direct, indirect, and induced impacts and proposed mitigation is included in this section and grouped according to the questions found in **Socioeconomics Table 1**, which follows.

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:				
A. 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:				
Fire protection			X	
Police protection			X	
Schools			X	
Parks			X	
Other public facilities			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				X
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

Induce Substantial Population Growth: No Impact

For the purpose of this analysis, *induce substantial population growth* is defined as people permanently moving into the area because of the construction and operation of the Beacon Solar Energy Project, thereby encouraging the construction of new homes and businesses or the extension of roads or other infrastructure. Based on that definition, BSEP will not encourage people to permanently move into the area. Consequently, the BSEP will have no direct or indirect impact on substantial population growth in a new area.

However, the construction of the BSEP will result in the influx of temporary workers to the area during the two-year construction period, which begins in third quarter 2009 and is expected to be completed within 25 months of the state date. The plant is expected to be operational during third quarter, 2011. Once operational, the plant will employ approximately 66 workers, most of whom would already reside in the area.

The peak number of temporary workers needed for the project is 836 and the average number of workers per day, 477. Those workers, who will likely come from the following counties: Kern, Los Angeles, and San Bernardino and commute to the project site.[3] For those workers, who will return home for the weekends, approximately 792 hotel and motel rooms are available near the BSEP site, including rooms in California City, Mojave, Rosamond, and Ridgecrest. In addition, at least five RV sites are located within 25 miles of the BSEP site. **Socioeconomics Table 3**, "Population, Housing Units, and Unemployment Rates," which follows, includes information designed to provide a snapshot view of the areas affected by the construction of the BSEP.

[3] According to *Socioeconomics of Power Plants*; Electric Power Research Institute, 1982, construction workers will travel two hours each way to a job site rather than relocate.

SOCIOECONOMICS Table 3
Population, Housing Units, and Unemployment Rates for Kern, Los Angeles, and Riverside Counties

County	Population (January 2008)	Unemployment Rate (Percent, Seasonally Unadjusted) (July 2008)	Vacant Housing Units/ Percent Vacant (January 2008)
Kern (Bakersfield Metropolitan Statistical Area California City (Closest to Site)	817,517 14,365	9.9 7.7	272,602/ 9.84
Los Angeles (Los Angeles-Long Beach Metropolitan Division)	10,363,850	8.1	3,403,489 4.2
San Bernardino (Riverside-San Bernardino-Ontario Metropolitan Statistical Area)	2,088,302	8.5	685,642 11.61

Source: California Department of Finance; California Employment Development Department

According to data available from the California Employment Development Department, those three counties will be able to provide the number of workers needed. See **SOCIOECONOMICS Table 4,** “Available Labor, by Skill, in Kern, Los Angeles, and San Bernardino Counties, 2004─2014, and Maximum Number of Workers Needed by Project,” which follows.

SOCIOECONOMICS Table 4
Available Labor by Skill in Kern, Los Angeles, and San Bernardino Counties, 2004–2014, and Maximum Number of Workers Needed by Project

Craft	**Kern County** (Bakersfield Metropolitan Statistical Area)	**Los Angeles County** (Los Angeles-Long Beach-Metropolitan Division	**San Bernardino County** (Riverside-San Bernardino-Ontario Metropolitan Statistical Area)	**Maximum Number of Workers Needed by Project**
Boiler Makers	150	190	7	11
Carpenters	1,990	23,620	28,050	72
Cement Masons	780	2,770	5,170	10
Construction Staff	N/AV	N/AV	N/AV	44
Construction Trade Workers	3,500	24,820	20,010	44
Electricians	1,590	6,690	6,730	253
Foreperson	800	10,770	4,080	18
Insulation Workers	4,300	420	220	56
Ironworkers	50	2,640	930	57
Laborers	13,140	13,520	20,010	100
Mechanics	560	2,720	1,120	4
Millwrights	N/AV	950	120	23
Operating Engineers	550	4,080	3,980	108
Painters	70	3,990	7,570	15
Pipefitters	1,080	12,580	4,660	339
Solar Field Subs	N/AV	N/AV	N/AV	7
Subcontractors	N/AV	N/AV	N/AV	8
Teamsters (Truck Drivers, Heavy and Tractor-Trailer	4,280	33,310	20,020	14
Technical Advisors	N/AV	N/AV	N/AV	6
Welders	810	8,250	3,950	36

Source: State of California Employment Development Department, Occupational Employment Projections, Occupation Profile; and Beacon Solar Energy Project AFC.
* Not Available (N/AV)

Displace Substantial Numbers of People, Necessitating New Construction: No Impact

This project will be constructed on a vacant, 2,012-acre site in eastern Kern County. The site is vacant and located near to transmission infrastructure. Consequently, the project will not displace substantial numbers of people, necessitating construction of new housing elsewhere.

Result in Substantial Adverse Physical Impacts to Government Services

This project will not cause significant impacts on service ratios, response times, or other performance objectives relating to law enforcement, medical services, fire and police protection; schools; and other public facilities. Staff's analysis follows.

Law Enforcement: Less than Significant Impact

Located at 1771 Highway 58 in Mojave, 16 miles from the proposed site, the Kern County Sheriff's Department would provide services for the project, including traffic and neighborhood police control, emergency calls, and crime prevention. The substation's response area—1,320 square miles—is one of the largest response areas in Kern County. The department's average response time is 23 minutes and 54 sections for a Type 1 and Type 2 incident (Personal communication (e-mail) to Marie McLean from Francis Moore, Commander, Kern County Sheriff's Office).

The state highways and roads near the BSEP are patrolled by the California Highway Patrol (CHP). The CHP enforces applicable laws; controls traffic; investigates accidents; and manages hazardous materials spills.

Population wise, the demand for law enforcement will not be significantly increased because most of the labor force would be commuting. For the operational phase, the change in population would be slight or nonexistent. Consequently, the project will not result in a less than significant impact on law enforcement services.

Medical Services: Less than Significant Impact

Staff finds a less than significant impact on medical services, including emergency services, associated with the construction and operation of the BSEP. Four hospitals are located within the BSEP area. Those hospitals include Ridgecrest Regional Hospital, Ridgecrest; Antelope Valley Hospital, Lancaster; and the Kern Medical Center, Bakersfield. In addition, Lancaster is also home to the Drummond Medical Group, which offers limited emergency and outpatient surgical services, and the LAC/High Desert Hospital, a short-term, 28-bed intensive care facility.

Three hospitals located less than 50 miles of the proposed site operate a 24-hour emergency room: (1) Antelope Valley Hospital, a 420-bed, acute-care facility in Lancaster, with a medical staff of 450 staff physicians; (2) Lancaster Community Hospital, Lancaster, a 117-bed, acute-care facility; and (3) Ridgecrest Regional Hospital, Ridgecrest, an 80-bed facility located in Ridgecrest.

Located approximately 70 miles from the project site in Bakersfield, the Kern Medical Center, a 222-bed, acute-care teaching hospital, operates the county's only trauma center. Owned and operated by Kern County and staffed by 65 physicians, Kern Medical Center works with the Kern County's Emergency Medical Services (EMS) Department, area hospitals, and ambulance companies to provide medical services necessary for critically injured patients in Kern County.

For additional information about medical services, please see the following sections of this assessment: **Worker Safety** and **Hazardous Materials**.

Fire Protection: Less than Significant Impact

Staff finds a less than significant impact on fire protection services resulting from the construction and operation of the BSEP. The Kern County Fire Department (KCFD) provides fire protection services to the BSEP site through its three closest fire stations, Station 14 in Mojave; Station 75 in Randsburg; and Station 73, in Inyokern. Station 14 would arrive in approximately 27 minutes; Station 75 in approximately 32; and Station 73, in approximately 43 minutes.

Through an agreement with the KCFD, the California City Fire Department provides services when needed. The fire department is located about 10 miles from the BSEP site. The average response time to the site for the Kern County Fire Department Station is approximately 17 minutes.

Schools and Other Public Facilities: Less than Significant Impact

Staff concludes that a less than significant impact to schools or other public facilities such as libraries, community centers, and day-care facilities during the construction and operation of the BSEP.

Construction workers would most likely commute to the project site. If the BSEP were to employ nonlocal construction workers, those workers would not likely relocate family members for the relatively short construction period. Instead, they would likely stay in local hotels, motels, or RV parks during the week and return home on weekends. Consequently, their use of public facilities is

Increase Use of Existing Recreational Facilities: No Impact

Two county and one state recreational areas are located in the vicinity of the BSEP site: the 5,000-acreTehachapi Mountain Park; the 1,102-acre Kern River County Park, with two picnic areas and golf course; and Red Rock Canyon State Park. All require advance reservations, either for campsites or picnic grounds. However, hiking trails at Tehachapi Mountain Park and Red Rock Canyon State Park may be accessed without reservations (Kern County Parks and Recreation, www.co.**kern**.ca.us/**parks**/).

The 25,665-acre Red Rock Canyon State Park is the closest recreational facility to the site—approximately four miles north of the project site—and is open sunrise to sunset for day use. Its 50-space campground, open 24 hours, is first-come, first-served. According to the Department of Parks and Recreation, the campground may fill up on weekends in spring and fall (California Department of Parks and Recreation, “Red Rock Canyon State Park, www.parks.ca.gov/default.asp?page_id=631).

The construction and operation of the BSEP would have no impact on existing county and state parks in the area, including Red Rock Canyon State Park for the following reasons:

1. Most workers would be commuting daily to and from their homes. The few who choose not to commute and instead stay in nearby hotels for the week would be returning home for the weekend.

2. Workers who chose not to return home for the weekend would need to make reservations to use facilities at each park. That reservation system is designed to prevent significant impacts on the parks.

3. Workers who chose not to return home for the weekend but instead wished to take advantage of the hiking trails could do so without resulting in a significant impact on the parks. The size of the parks—from 25,665 to 1,102 acres—are large enough to accommodate the small number of temporary workers who may want to use the trails without resulting in a significant impact.

Includes recreational facilities or requires the construction or expansion of recreational facilities: No impact.

This project does not include recreational facilities; not does it require the construction or expansion of recreational facilities.

Cumulative Impacts and Mitigation

A project may result in significant adverse cumulative impacts when its effects are cumulatively considerable; that is, when the incremental effects of an individual project are significant when viewed in connection with the effects of (1) past projects; (2) other current projects; and (3) probable future projects [*Public Resources Code* Section 21083; *California Code of Regulations*, Title 14, Sections 15064(h); 15065 (c); 15130; and 15355]. Mitigation requires taking feasible measures to avoid or substantially reduce the impacts.

In a socioeconomic analysis, cumulative impacts could occur when more than one project in the same area has an overlapping construction schedule, thus creating a demand for workers that cannot be met locally. That increased demand for labor could result in an influx of non-local workers and their dependents, resulting in a severe strain on housing, schools, parks and recreation, law enforcement, and medical services.

The construction schedules of two Los Angeles Department of Water and Power (LADWP) renewable energy projects—Pine Tree Wind Development Project and the Barren Ridge-Castaic Transmission Project—will overlap with the construction schedule of the BSEP.

According to the applicant, construction of the BSEP is scheduled to begin June 2009 and continue through June 2011. As reported by LADWP, construction on the Pine Tree Wind Development Project began in early 2008. The project is expected to be operational in early 2010. Construction on the Barren Ridge-Castaic Transmission Project is expected to begin in mid-to- 2010 and continue through mid-to-late 2013, approximately two years after construction on the BSEP is completed.

Consequently, the construction schedules of the BSEP and the Pine Tree Wind Development Project will overlap for approximately six months; the construction schedule for the BSEP and the Barren Ridge-Castaic Transmission Project, approximately one year.

In addition, According to the Socioeconomics section of *Findings of No Significant IMPACT-FONSI* (40 CFR 1508.13), prepared by the Bureau of Land Management for the project, LADWP has agreements with a number of motels in the area to temporarily house workers on the Pine Tree Wind Project. That housing agreement, combined with the influx of workers for both the BSEP and the Barren Ridge-Castaic Transmission Project, could result in fewer rooms available for BSEP workers, thus contributing to a significant cumulative impact.

Consequently, staff analyzed the cumulative impacts on housing, schools, parks and recreation, law enforcement, and medical services resulting from the overlapping schedules. The results of the analysis, arranged according to housing; schools, parks and recreation; law enforcement, and medical services; and mitigation follows.

Housing, Schools, Parks, and Recreation

The construction schedule for the Pine Tree Wind Development Project will overlap for approximately six months; the construction schedule for the Barren-Ridge-Castaic Transmission Project, for about one year. However, impacts on housing, schools, parks and recreation, law enforcement, and medical services resulting from the overlapping schedules will not result in a significant cumulative impact for the following reasons:

1. For the BSEP, the average number of workers per day is expected to be 477. Those workers will likely commute from Kern, Los Angeles, and San Bernardino counties. For workers who wish to stay in the area, a sufficient number of rooms are available even considering the the arrangements made by LADWP to house the Pine Tree Wind Project workers. Hence, those workers will not affect the number of rooms available for the LADWP projects. See item 4, below. In addition, workers who chose to stay in the area will be returning home on the weekends. As a result, the impact on housing, schools, parks and recreation, law enforcement, and medical services will not result in a significant cumulative impact.

2. Most workers on the Pine Tree Wind Project are likely to come from the counties of Kern, Los Angeles, and San Bernardino, the same areas as BSEP workers. According to **Socioeconomics Table 3**, a sufficient number of workers are available to work on the project as well as on the BSEP. In addition, most of those workers are likely to commute to and from the project site.

3. The Barren Ridge-Castaic Transmission Project, which will span 75 miles from the Mojave Desert to San Fernando Valley, will be built in stages. Hence, workers will be working in an area ranging from Kern County to northwest Los Angeles County during the three-year construction period. Those workers are also likely to commute from Kern, Los Angeles, and San Bernardino counties.

4. Staff has identified at least 792 hotel and motel rooms in the area, including rooms in California City, Mojave, Rosamond, and Ridgecrest. In addition, at least five RV sites are located within 25 miles of the BSEP site. Consequently, a sufficient number of rooms exist in the area to accommodate workers from all

5. three projects who do not wish to commute but remain in the area. However, those workers will not relocate to the area with their families. Instead, they are likely to return home on weekends.

Mitigation

Staff found no socioeconomic cumulative impacts associated with the construction and operation of the BSEP. Therefore, mitigation measures were not required.

NOTEWORTHY PUBLIC BENEFITS

Noteworthy public benefits include the direct, indirect, and induced impacts of a proposed power plant. Determining and reporting those impacts is a primary task in developing a socioeconomic analysis. [4]

For purposes of this analysis, direct impacts were said to exist if the project resulted in permanent jobs and wages; indirect impacts, if jobs, wages, and sales resulted from constructing the project; induced impacts, from the spending of wages and salaries on food, housing, and other consumer goods. See **Socioeconomics Table 5**, “Noteworthy Public Benefits Related to Beacon Solar Energy Project,” which follows.

[4] The dollars spent on or resulting from the construction and operation of the BSEP will have a ripple effect on the local economy. For example, BSEP owners employ workers, both temporary and permanent; and purchase supplies and services for the life of the plant. Employees use salaries and wages to purchase goods and services from other businesses. Those businesses make their own purchases and hire employees, who also spend their salaries and wages throughout the local and regional economics. This chain reaction of indirect (jobs, sales, and income generated, for example) and induced (employees’ spending for local goods and services, for example) spending continues with subsequent rounds of additional spending, which is gradually diminished through savings, taxes, and expenditures made outside the area. This ripple effect is measured by an “Input-Output” economic model. The model relies on a series of multipliers to provide estimates of the number of times each dollar of input or direct spending cycles through the economic in terms of indirect and induced output, or additional spending, personal income, and employment. Several inout-output models are commonly used by economists, including the IMPLAN input-output model used the the applicant. IMPLAN multipliers indicate the ratio of direct impacts to indirect and induced impacts. Staff reviewed the results of the IMPLAN model and found them to be reasonable considering data provided by the applicant as well as data obtained by staff from governmental agencies, trade associations, and public interest research groups.

SOCIOECONOMICS Table 5
Noteworthy Public Benefits
Related to Beacon Solar Energy Project
(2008 Dollars)

Fiscal Benefits	
Estimated annual property taxes (with solar tax credit)	$440,000
Estimated annual property taxes (without solar tax credit)	$4.24—$4.90 million
State and local sales taxes: Construction	$1,045,000
State and local sales taxes: Operation	$435,000 per year
School Impact Fee	$10,400
Gas franchise fees	Data Request/Info to Follow around Nov 6.
Non-Fiscal Benefits	
Total capital costs	$180 million
Construction payroll	$165.5 million
Operations payroll	$7 million to $8 million
Construction materials and supplies	$14.5 million
Operations and maintenance supplies	$6 million per year
Direct, Indirect, and Induced Benefits	
Estimated Direct Employment	
Construction and commissioning (average)	477 jobs
Operation	66 jobs
Estimated Secondary Employment	
Construction and Commissioning	298 jobs
Operation	98 jobs
Estimated Secondary Income	
Construction and Commissioning	$124 million
Operation	$1.6 million

RESPONSE TO COMMENTS

No comments were received on this project.

REFERENCES

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"Red Rock Canyon State Park, www.**park**s.ca.gov/default.asp?page_id=631).

Kern County Parks and Recreation, www.co.**kern**.ca.us/**parks**/.

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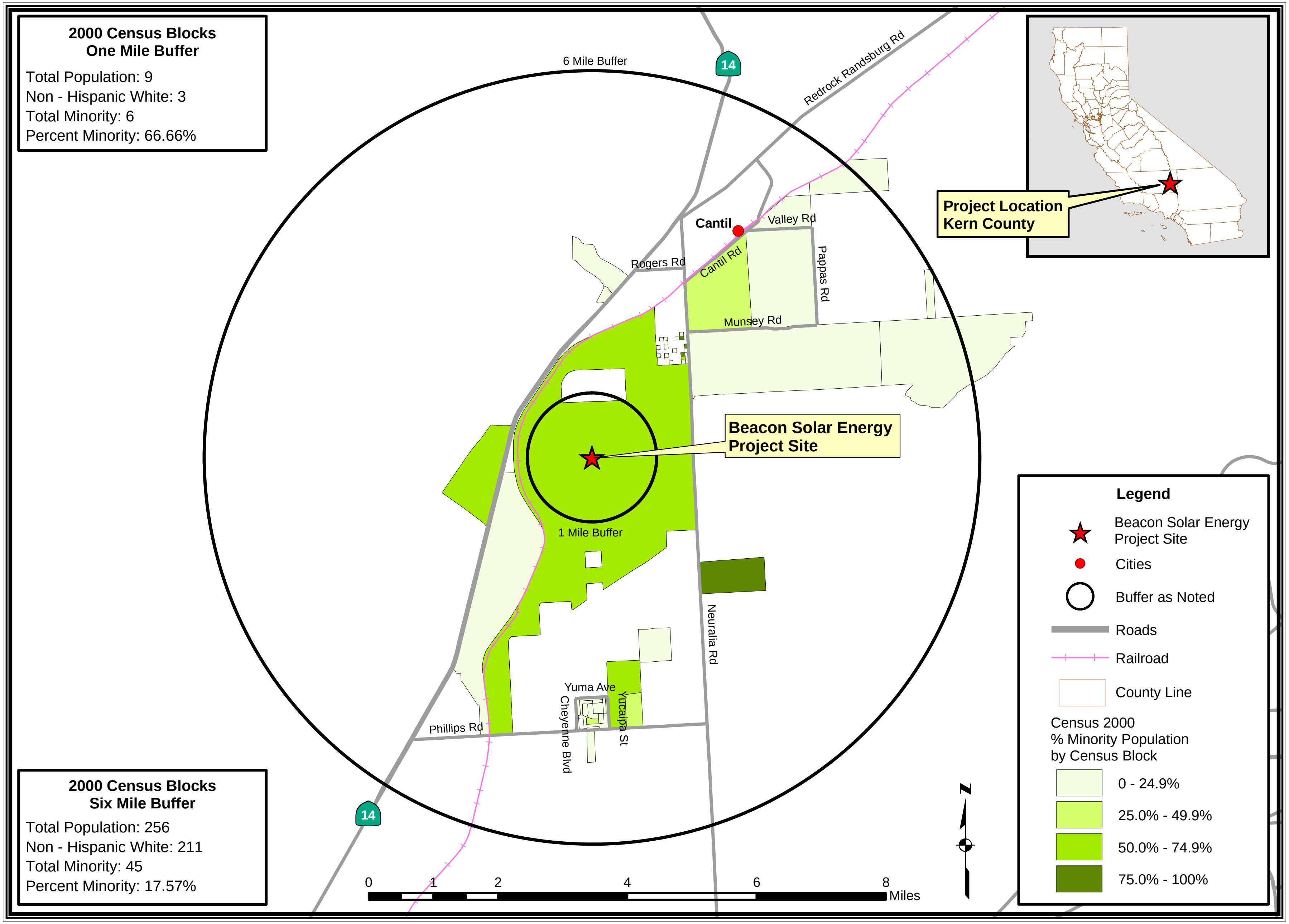
SOCIOECONOMICS - FIGURE 1

Beacon Solar Energy Project - Census 2000 Minority Population by Census Block - One and Six Mile Buffer



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING DIVISION, APRIL 2009

SOURCE: California Energy Commission Statewide Power Plant Maps 2008 - Census 2000 PL 94-171 Data - Matrix PL2

SOIL AND WATER RESOURCES

Casey Weaver, P.G., Vince Geronimo, P.E., John L. Fio, and Michael N. DiFilippo

SUMMARY OF CONCLUSIONS

As proposed, the project will cause significant environmental impacts, does not comply with existing water policies, and, in some cases, does not comply with LORS. A summary of staff conclusions is presented below.

- The proposed use of high quality fresh groundwater for power plant cooling is in conflict with State Water Resources Control Board and Energy Commission policies.
- There is no compelling evidence that using the lowest quality water supply reasonably available (brackish water near Koehn Lake) would be environmentally undesirable or economically unsound.
- There is no compelling evidence that alternative cooling technologies would be environmentally undesirable or economically unsound.
- Staff analysis shows other alternatives to wet cooling may be economically feasible.
- Staff believes the applicant should further evaluate alternative water supplies and/or cooling technologies and propose a design alternative that eliminates fresh water use for evaporative cooling.
- Historic groundwater pumping in the Fremont Valley Basin has resulted in groundwater overdraft and subsidence.
- Historic groundwater pumping in the Fremont Valley Basin has changed hydraulic gradients which could cause saline groundwater beneath Koehn Lake to flow towards freshwater portions of the basin.
- Groundwater level trends in the Fremont Valley Basin indicate current water levels remain substantially lower than historic high water levels and in some areas a continued decline.
- The balance between water inflows and outflows in Freemont Valley groundwater sub-basins, and the Basin on a whole, is sensitive to changes in groundwater pumping rates and use.
- Groundwater levels in the Koehn Groundwater Sub-basin, which underlies the project site, have been slowly increasing or remain nearly steady; water levels in at least one well have been declining.
- The proposed use of onsite groundwater from the Koehn Sub-basin can more than double current consumption, affecting the water levels and storage volumes of a potable water supply.
- The groundwater model does not accurately portray existing groundwater conditions.
- The model calibration was updated in December 2008, but a number of previously reported simulations were not updated to reflect changes in modeled-aquifer parameters. Therefore, a lack of consistency exists between simulated impact and sensitivity test model runs.

- Project groundwater pumping could result in well interference and impact nearby groundwater users.
- The project site is bisected by a mapped Special Flood Hazard Area. As proposed, the diversion channel intending to reroute flood flows around the project site is not adequate for 100-year flood flows.
  - The proposed design for filling and realigning Pine Tree Creek does not meet Kern County standards and may result in a significant impact to adjacent property owners.
- The proposed site drainage plan is designed to collect and discharge concentrated runoff directly into the rerouted channel without reducing sediment loads, or removing site-generated contaminants.
- The runoff detention basins are not adequately designed to capture design storm site runoff.
- There is no plan for collecting, treating and disposing storm water that has been in contact with the power block or other mechanical equipment.
- As proposed, the evaporation ponds for wastewater disposal are not sufficiently sized to contain the anticipated waste stream.
- Staff recommends that the following engineering studies be provided for review so staff can complete an analysis of potential environmental impacts from the proposed reconfiguration of Pine Tree Creek:
  - Revised Conceptual Drainage Study
  - Geomorphic Study
  - Revised Diversion Channel Design
  - Soils Engineering Report
- Staff recommends that the applicant provide verification that a maintenance district is being developed in accordance with LORS and to address County maintenance concerns for Pine Tree Creek.

INTRODUCTION

This section analyzes potential impacts to soil and water resources from the construction and operation of the Beacon Solar Energy (BSEP) project. The analysis specifically focuses on the potential for BSEP to:

- cause accelerated wind or water erosion and sedimentation;
- exacerbate flood conditions in the vicinity of the project;
- adversely affect surface or groundwater supplies;
- degrade surface or groundwater quality; and
- comply with all applicable laws, ordinances, regulations, and standards (LORS) and state policies.

Where the potential for impacts are identified, staff has proposed mitigation measures to reduce the significance of the impact, if possible, and has recommended conditions of certification.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

The following federal, state, and local environmental Laws, Ordinances, Regulations, and Standards (LORS) have been established for the BSEP. Compliance with LORS ensures the most appropriate use and management of both soil and water resources. The requirements of these LORS are specifically intended to protect human health and the environment. The potential for project compliance with these LORS is a major component of staff's analysis.

Soil & Water Table 1
Laws, Ordinances, Regulations, and Standards

Federal LORS	
Clean Water Act (33 U.S.C. Section 1251 et seq.)	The Clean Water Act (33 USC § 1257 et seq.) requires states to set standards to protect water quality, which includes regulation of storm water and wastewater discharges during construction and operation of a facility. California established its regulations to comply with the Clean Water Act under the Porter-Cologne Water Quality Control Act of 1967. The Clean Water Act also establishes protection of navigable waters through Section 401. Section 401 certification through the Army Corps of Engineers and Regional Water Quality Control Board (RWQCB) is required if there are potential impacts to surface waters of the State and/or Waters of the United States, such as perennial and ephemeral drainages, streams, washes, ponds, pools, and wetlands. Section 401 requires impacts to these waters to be quantified and mitigated.
Resource Conservation and Recovery Act	The Resource Conservation Recovery Act (RCRA) of 1976 (40 CFR Part 260 et seq.) seeks to prevent surface and groundwater contamination, sets guidelines for determining hazardous wastes, and identifies proper methods for handling and disposing of those wastes.
Title 44 of the Code of Federal Regulations (44 CFR) Part 65	44 CFR contains the basic policies and procedures of the Federal Emergency Management Agency (FEMA) for adoption of rules. Part 65 - Identification and mapping of special hazard areas requires development in areas identified as a FEMA Special Flood Hazard Area to meet the requirements of Title 44 of the Federal Code of Regulations (44CFR)
State LORS	
California Constitution, Article X, Section 2	This section requires that the water resources of the State be put to beneficial use to the fullest extent possible and states that the waste, unreasonable use or unreasonable method of use of water is prohibited.
The Porter-Cologne Water Quality Control Act of 1967, Water Code Sec 13000 et seq.	Requires the SWRCB and the nine RWQCBs to adopt water quality criteria to protect state waters. Those regulations require that the RWQCBs issue Waste Discharge Requirements specifying conditions for protection of water quality as applicable.

California Water Code (CWC) Section 13146	Requires that state offices, departments and boards in carrying out activities, which affect water quality, shall comply with state policy for water quality control unless otherwise directed or authorized by statute, in which case they shall indicate to the State Water Resources Control Board in writing their authority for not complying with such policy.
California Water Code Section 13551	Requires the water resources of the State be put to beneficial use to the fullest extent of which they are capable, and the waste or unreasonable use or unreasonable method of use of water be prevented, and that the conservation of such water is to be exercised with a view to the reasonable and beneficial use thereof in the interest of the people and for the public welfare.
Recycling Act of 1991 (Water Code 13575 et. seq)	States that retail water suppliers, recycled water producers, and wholesalers should promote the substitution of recycled water for potable and imported water in order to maximize the appropriate cost-effective use of recycled water.
SWRCB WQO 99-08	The SWRCB regulates storm water discharges associated with construction projects affecting areas greater than or equal to 1 acre to protect state waters. Under Order 99-08, the SWRCB has issued a National Pollutant Discharge Elimination System (NPDES) General Permit for storm water discharges associated with construction activity for which applicants can qualify if they meet the criteria and upon preparing and implementing an acceptable SWPPP and notifying the SWRCB with a Notice of Intent.
California Code of Regulations, Title 22, Division 4, Chapter 15	This Chapter specifies Primary and Secondary Drinking Water Standards in terms of Maximum Contaminant Levels (MCLs). These MCLs include total dissolved solids (TDS) ranging from a recommended level of 500 milligrams per liter (mg/l), an upper level of 1,000 mg/l and a short term level of 1,500 mg/l. Other water quality MCLs are also specified, in addition to MCLS specified for heavy metals and chemical compounds.
California Code of Regulations, Title 23, Division 3, Chapter 15	This Chapter requires the Regional Board to issue Waste Discharge Requirements specifying conditions for protection of water quality as applicable.
California Water Code Section 13260	Requires filing with the appropriate Regional Board a report of waste discharge that could affect the water quality of the state, unless the requirement is waived pursuant to Water Code section 13269.
The California Safe Drinking Water and Toxic Enforcement Act	The California Health & Safety Code Section 25249.5 et seq. prohibits actions contaminating drinking water with chemicals known to cause cancer or possessing reproductive toxicity. The RWQCB administers the requirements of the Act.
Local LORS	
Kern County Ordinance Code, Title 4, Chapter 14.08 – Water Supply Systems	Regulates permitting, siting, construction and destruction of groundwater wells.
Kern County Code Title 14, Chapter 14.20.050 – Private Sewage Disposal Systems	Provides authority for health department to make uniform rules, regulations and requirements regarding the construction and maintenance of private sewage disposal systems.
Kern County Environmental Health Services Department, Chapter II, Section 602, Sewage Disposal by Individual Soil Absorption Systems	Regulates construction of on-site sewage disposal systems.

Kern County Uniform Plumbing Code, Chapter 17	Regulates installation and requires inspection for locating disposal/leach fields, or seepage pits.
Kern County Division Four, Standards for Drainage	Provides standards for drainage of waters generated by storms, springs, or other sources that should be mitigated so as to provide reasonable levels of protection for life and property, and the maintenance of necessary access to property or passage of the traveling public on the public highways,.
Kern County Code Of Building Regulations Chapter 17.48 Floodplain Management	Regulates development of projects in special flood hazard areas. These regulations are designed to comply with the National Flood Insurance Program regulations.
State Policies and Guidance	
State Water Resources Control Board (SWRCB) Res. 77-1	State Water Resources Control Board Resolution 77-1 encourages and promotes recycled water use for non-potable purposes.
SWRCB Resolutions 75-58	The principal policy of the SWRCB that addresses the specific siting of energy facilities is the Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling (adopted by the Board on June 19, 1976, by Resolution 75-58). This policy states that use of fresh inland waters should only be used for power plant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound.
2003 Integrated Energy Policy Report (IEPR)	In this report, consistent with SWRCB Policy 75-58 and the Warren-Alquist Act, the Energy Commission adopted a policy stating the Commission will approve the use of fresh water for cooling purposes by power plants only where alternative water supply sources and alternative cooling technologies are shown to be “environmentally undesirable” or “economically unsound.”

SETTING

The BSEP would be located in the Fremont Valley, in an unincorporated part of eastern Kern County near California City. The Fremont Valley is in the northwestern portion of the Mojave Desert where water resources are extremely limited.

REGIONAL WATER RESOURCES

The Fremont Valley Groundwater Basin is located in the South Lahontan Hydrologic Region of the Mojave Desert (DWR 2003). Within the desert environment of the South Lahontan Hydrologic Region, the occurrence and use of water resources are complicated issues. In this region, groundwater often supplements imported State Water Project or Colorado River water for domestic, agricultural, commercial and industrial water uses. The Region covers about 33,100 square miles and is bounded to the west by the crest of the Sierra Nevada; to the north by the watershed divide between Mono Lake and East Walker River drainages; to the east by the California-Nevada border; and to the south by the crest of the San Gabriel, the San Bernardino mountains and the divide between watersheds draining south toward the Colorado River and those draining to the north. The South Lahontan Hydrologic Region includes the Owens, Mojave, and Amargosa River systems, the Mono Lake drainage system and numerous other internally drained basins.

The South Lahontan Hydrologic Region is subdivided into 76 groundwater basins, one of which is the Fremont Valley Groundwater Basin (RWQCB 1994). The BSEP and surrounding area is underlain by the Fremont Valley Groundwater Basin.

Surface water in the Fremont Valley originates in the surrounding mountains and flows toward Koehn Lake, a dry lake or playa, which is located approximately six miles northeast of the BSEP site. Most of the surface water infiltrates into the alluvium-filled valley and any surface flow that does not infiltrate or evaporate, discharges to Koehn Lake. Koehn Lake is a highly saline wet playa. The playa is a flat, vegetation-free area located at the lowest part of the undrained desert basin. There is no surface water outflow from the Fremont Valley due to low precipitation rates, high soil infiltration rates, high evapotranspiration rates and the topographic low of Koehn Lake.

Fremont Valley Groundwater Basin

The Fremont Valley Groundwater Basin is divided into six sub-basins: California City, Koehn, Chaffee, Gloster, Oak Creek, and Willow Springs (BS 2008a, Figure 5.17-1). The sub-basins are typically separated by faults that form partial barriers to groundwater movement (Bloyd 1967, Koehler 1977, Saint-Armand 1991).

The primary source of water to the Fremont Valley is surface water infiltration and potentially underflow from the south (SAMDA 1997). Groundwater recharge resulting from precipitation on the valley floor is considered minimal because direct rainfall is significantly less than the potential evapotranspiration rate and potential soil moisture retention. In portions of the basin where development has occurred, used water may return to the basin’s aquifer through discharge of septic systems, and by inefficient irrigation practices.

KOEHN SUB-BASIN

The BSEP is located within the Koehn sub-basin of the Fremont Valley Groundwater Basin. The Koehn sub-basin is bounded by the California City sub-basin to the southeast, the Chaffee sub-basin to the south and the Oak Creek sub-basin to the southwest (BS 2008a, Figure 5.17-1). The physical boundaries include the Randsburg-Mojave Fault and Rand Mountains to the east and southeast; the El Paso Mountains to the northwest; the Sierra Nevada Mountains and the Garlock East Fault to the west; and the confluence of the El Paso and Rand Mountains to the northeast (Weir et al. 1965, Bloyd 1967, DWR 1968, Moyle et. al., 1985, DWR 2003).

Subsurface alluvial deposits in the Koehn Lake sub-basin vary in thickness between approximately 400 feet thick to over 1,700 feet thick and consist of variable mixtures of sand and gravel with interspersed, non-continuous clay lenses. Depth to groundwater also varies throughout the sub-basin and ranges from more than 300 feet deep away from the lake to as shallow as approximately 14 feet deep in the immediate vicinity of the lake.

Large scale alfalfa farming began within the sub-basin in the mid-1950’s and extended through the mid 1980s. During this time, groundwater pumping lowered the water table several hundred feet, which formed a large groundwater depression and caused land subsidence within the sub-basin. Due to the lowered groundwater elevation, pumping costs increased to a point that farming was no longer profitable and most farming operations ceased.

Groundwater quality in the Koehn sub-basin varies spatially in relationship to Koehn Lake. In the southwest portion of the sub-basin, water quality is of sodium bicarbonate or calcium-sodium bicarbonate types (DWR 2003). Due to evaporative concentration of salts, Total Dissolved Solids (TDS) concentrations increase and water quality decreases toward Koehn Lake. Beneath Koehn Lake, the TDS concentration of the groundwater is as high as 100,000 mg/L (Dockter, 1979, DWR, 2003). Southwest of the lake bed, and near the proposed BSEP site, typical TDS concentrations are reportedly about 500 mg/L.

PROJECT, SITE, AND VICINITY SETTING

As proposed, the BSEP would be a concentrated thermal solar electric generating facility constructed on an approximately 2,012-acre site in eastern Kern County, California. The project would have a nominal electrical output of 250 megawatts (MW).

BSEP proposes to use a wet cooling tower for power plant cooling. Water for cooling tower makeup, process water makeup, and other industrial uses such as mirror washing, would be supplied from onsite groundwater wells, which also would supply water for employee use (e.g., drinking, showers, sinks, and toilets).

Of the 2,012-acre property, the BSEP power block and solar arrays would occupy approximately 1,240 acres, with the proposed rerouted drainage channel, evaporation ponds, roadways, administration buildings and other support facilities occupying the remainder of the acreage.

The BSEP site is almost completely vacant and significantly disturbed from past agricultural activities that ended in the mid-1980s. There are several abandoned structures in a small area just east of SR-14 and west of the site boundary.

The site is bisected by an active splay of the Garlock Fault named the Cantil Fault. The Cantil Fault is expressed on the site as a relatively steep, west facing slope that vertically separates two relatively flat sections of the property by an elevation of approximately 20 feet. Elevations across the site from the southeast to the northwest range from approximately 2,220 to 2,025 feet above mean sea level.

Pine Tree Creek, a dry desert wash, trends from the south-southwest to the north-northeast through the center of the site. The creek is mapped as a 100-year flood hazard zone by the Federal Emergency Management Agency (FEMA) where it crosses the site. BSEP proposes to fill the existing creek channel and reroute Pine Tree Creek around the south and east periphery of the solar facility.

SURFACE WATER

There are three main watersheds that contribute surface water flow in the BSEP site vicinity. These watersheds are the Pine Tree Creek Watershed, Jawbone Creek

Watershed and an unnamed watershed located adjacent to the Pine Tree Creek Watershed. Discussion of these watersheds is presented below.

Pine Tree Creek Watershed

Pine Tree Creek originates from the Pine Tree Canyon where the Sierra Nevada Mountain Range becomes the Tehachapi Mountains, west of the BSEP site. The Pine Tree Creek headwaters are located at Cache Peak. Pine Tree Creek descends the flanks of the mountains, forms an alluvial fan, traverses the project site and ultimately discharges to Koehn Lake. The topographical apex of the Pine Tree Creek alluvial fan is located at the mouth of Pine Tree Canyon and was formed from sediment washing out from the canyon. This alluvial fan is evident from topographic and aerial maps reviewed by staff. The alluvial fan is crossed by two Los Angeles Department of Water and Power aqueducts, State Route -14 (SR-14) about a mile downstream from the apex, and the Southern Pacific Rail Road (SPRR). An existing six cell 8-foot by 8-footReinforced Concrete Box (RCB) culvert passes Pine Tree Canyon flows past SR-14. Downstream of the SPRR, the channel confluences with the Barren Ridge drainage from the south and continues northeasterly toward the BSEP site.

A large portion of the southern half of the Pine Tree Creek watershed includes the sub-watershed area east of Barren Ridge. From a high elevation of approximately 4,200 feet, runoff comes down from the ridge through several small drainage swales to the alluvial area west of SR-14. A drainage ditch along the west side of SR-14 collects the watershed runoff and routes it to a double barrel 8-foot by 6-foot RCB at SR-14. The flow under crossing SR-14 continues northeasterly, beneath the SPRR tracks, and continues along its historic alignment. This sub-watershed eventually confluences with Pine Tree Creek in the alluvial flats about 1,000 feet east of SPRR. Downstream of this location, the channel enters the BSEP property.

The area east of Chuckwalla Mountain drains from an elevation of 4,900 feet toward the BSEP site. Runoff from Chuckwalla Mountain travels through several distributaries before being cutoff by SR-14. SR-14 has several existing culverts to convey flows to the east side of the road and past SPRR. Drainage channels are formed downstream of these crossings and are eventually diverted north through ditches outside of the BSEP property boundaries (BS 2008a), apparently deflecting what appears to be the natural drainage path of these channels away from the site.

In the AFC (BS 2008a), the applicant has identified a smaller tributary area located between Pine Creek Canyon and the Chuckwalla drainage area (Sheds 1S & 3S). The applicant has identified this “shed” as a nearly 1.5 square-mile basin that currently drains across the site after crossing through an existing SPRR culvert. This drainage area becomes a regulated Water of the State as it crosses the Beacon Solar property.

Jawbone Creek Watershed

The Jawbone Creek Watershed drains several canyons located in the Tehachapi Mountains. These canyons experience climatic conditions similar to Pine Tree Canyon. The names of these canyons are, from south to north, Alphie Canyon, Cottonwood Creek Canyon, Water Canyon, Jawbone Canyon and Red Rock Canyon.

Jawbone Canyon ends at the base of the mountainous and canyon areas. Jawbone Creek leaves the canyon at this location and drains to SR-14 and then to SPRR on the alluvial flats. At the SPRR tracks, the FEMA flood mapping shows a split in Jawbone Creek flow condition. One path leads to the north, and the other south toward the BSEP site. The southern channel bends easterly before reaching the northernmost BSEP property boundary. This reach is mapped by FEMA as a Special Flood Hazard Area (SFHA); Zone AE, Base Flood Elevations determined. The SFHA is nearly one-mile wide at this location north of the site. The Jawbone Creek flood hazard is not mapped within the BSEP property boundary. Near the BSEP site, the watershed area for Jawbone Creek is roughly 280 square miles. From adjacent to the BSEP site, Jawbone Creek flows easterly toward the Honda Proving Center and eventually to Koehn Lake, nearly 6 miles downstream from the site.

Unnamed Watershed (Adjacent to Pine Tree Creek Watershed)

Along the BSEP eastern property boundary, an unnamed drainage channel enters the BSEP site from the south. The watershed for this drainage is located immediately east of Pine Tree Creek watershed on the Fremont Valley alluvial plain. The watershed has an area of roughly 8-square-miles and drains to Jawbone Creek at nearly the same location where Pine Tree Creek joins Jawbone Creek.

SOILS

The majority of project facilities would be located on soil units that have rapid permeability and negligible to low runoff potential **(Soil & Water Table 2)**. The exceptions are areas underlain by the Rosamond clay loams, which have moderate runoff potential. The runoff designation for Cajon loamy sand is low, and the designation for Rosamond clay loam is moderate. In contrast, the Cajon loamy sand has rapid permeability whereas the Rosamond clay loam has a moderate to moderately slow permeability.

Soil & Water Table 2
Soil Types Potentially Affected & Characteristics

Primary Soil Name	Slope Class	Water Erosion Potential	Wind Erosion Potential	Permeability (in/hr)	Shrink-Swell Potential
Cajon Loamy Sand	0 -15%	Slight to Moderate	High	Rapid	Low
Cajon Gravelly Loamy Sand	0 to 15 %	High	High	Rapid	Low
Garlock Loamy Sand	2 to 9 %	Moderate	Moderate	Rapid	Low
Rosamond Clay Loam, Saline-Alkali	0 to 2 %	Moderate	Moderate	Moderate to Moderately Slow	Low to Moderate
Rosamond Clay Loam	0 to 2 %	Moderate	Moderate	Moderate to Moderately Slow	Low to Moderate

Source: U.S. Department of Agriculture's Soil Conservation Service Soil Survey of Kern County, California, Southeastern Part (1981)

BSEP site soils would be subject to wind and water erosion during facility construction and operation activities. Only two soil types would be affected by grading and excavation activities; Cajon loamy sand and Rosamond clay loam. The soils on the project site have a moderate to high hazard for wind erosion.

CLIMATE

The BSEP site is situated in the northwestern portion of the Mojave Desert. The climate in the Mojave Desert is dry and arid and characterized by low precipitation. The region experiences a wide variation in temperature, with very hot summer months (an average maximum temperature of 104 ºF occurring in July) and cold dry winters (average minimum temperature of 28 ºF occurring in December). Annual precipitation in the Mojave Desert ranges from three inches to six inches (U.S. Department of Agriculture 1981). **Soil & Water Table 3** displays the average monthly and annual minimum and maximum temperatures and total annual precipitation from 1971 to 2000. This data was collected from a gauging station in Cantil (Station 041488), located about one mile north of the Project (BSEP 2008a).

Soil & Water Table 3
Cantil, California Climate and Precipitation Summary[1] 1971 through 2000

Climate	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual[2]
Ave Max Temp (°F)	58.9	65.6	71.5	76.2	86.5	97.7	104.3	102.1	93.1	80.2	64.1	58.0	80.1
Ave Min Temp (°F)	28.9	33.9	40.8	46.1	55.0	63.8	69.2	67.1	57.1	44.1	34.7	28.2	47.5
Ave Total Precip (in)	0.71	0.48	0.33	0.09	0.15	0.05	0.10	0.12	0.05	0.06	0.43	0.54	3.05

[1] Source – Western Regional Climate Center, http://www.wrcc.dri.edu/ (Climate Station 041488 – Cantil)
[2] Refers to the annualized average of monthly temperature and precipitation values.

In the lee (down wind side) of the Tehachapi Range, precipitation in the site vicinity averages 3 to 6 inches a year, but is extremely variable. Snow and winter rains result from North Pacific cyclonic storms. Snowfall is infrequent and considered insignificant for staff's review. The remainder of precipitation comes from intense, local thunderstorms and summer tropical storms (FEMA 2008). Local thunderstorms are usually associated with convective (the vertical transport of heat and moisture in the atmosphere) activities and normally occur in the summer. The summer convective storms (thunderstorms) are generally dominant in the southern desert area (West 2007).

STORM WATER

The existing storm water flow across the project site is from southwest to northeast and occurs as sheet flow. Pine Tree Creek, a dry wash that conveys flash flood flows, bisects the site. The power plant would be constructed on a cut and fill pad with storm water intercepted by shallow ditches which would either 1) direct collected drainage into a proposed diversion channel or, 2) into a shallow retention basin proposed for construction in the solar field. Some of the collected runoff would be retained in a shallow depression designed for that purpose. Flows exceeding the capacity of the retention basin are designed to be discharged off site via a rocklined spillway.

Storm water would be managed in accordance with the Storm Water Pollution Prevention Plan (SWPPP) and the Drainage Erosion and Sediment Control Plan (DESCP). Both plans establish methods of when and how to control and manage storm water flow as it reaches the project, flows across the project, and then leaves the project. Draft plans have been prepared for both the construction and operational phases of the project.

During construction, the existing channel of Pine Tree Creek would be filled and the channel rerouted around the southern and eastern sides of the project. Following filling and rerouting of Pine Tree Creek, the site would be graded to gently slope from the southwest to the northeast. This grading is designed to direct storm induced sheet flow into transverse intercept trenches that convey collected runoff either directly into the rerouted Pine Tree Creek channel or into onsite retention basins. Six of these intercept trenches (the southernmost six) are designed to discharge directly into the rerouted channel. The northern three are proposed to convey flows to an onsite retention basin. Following settlement of suspended sediments and attenuation of peak flows in the retention basin, the collected storm water is designed to percolate and evaporate within seven days following the precipitation event.

Following site construction, the applicant proposes to revise the FEMA designated SFHA so that the proposed power block would not be located within a flood hazard area. Part of the natural gas transmission line would be constructed within a FEMA designated 100 to 500-year flood zone area (Zone A) or area subject to a 100-year flood.

The BSEP Conceptual Drainage Study addresses storm water issues related to the development. In order to comply with the Energy Commission's "in lieu permit" authority established under the Warren-Alquist Act, staff has coordinated joint environmental review with other agencies such as the U.S. Fish and Wildlife Service, California Department of Fish and Game (CDFG), Regional Water Quality Control Board (RWQCB) and Kern County. As part of this coordinated review, a copy of the study was submitted to the CDFG as part of an application for a Streambed Alteration Agreement. Additionally, a copy of the study was provided to the Lahontan Regional Water Quality Control Board (LRWQCB) and to Kern County for comment. Staff recognizes the value of these agency comments and refers to them during the impacts discussion below.

PROJECT WATER SUPPLY

BSEP proposes to use high quality fresh groundwater from onsite wells during construction (primarily during grading) and for operations phase process water needs (primarily evaporative cooling). The project is estimated to consume approximately1,600 acre-feet per year (AFY) of high quality fresh groundwater supplied by several existing onsite water wells. Pumping test data show that on-site wells have sufficient capacity (at least 2,000 gallons per minute) to meet the project's water supply requirements.

<u>Potable Water Use</u>

With minimal treatment, groundwater from onsite wells would meet the potable water demands of the BSEP operations workforce. The estimated annual potable water demand is 8 AFY. During construction, potable water use would be limited to drinking water provided in bottles. Waterless portable facilities would be used for sanitary needs.

Construction Water Use

The BSEP proposes to meet site pre-watering, grading and normal construction activity (e.g., mixing concrete, dust control) water requirements using water supplied from existing onsite wells equipped with temporary pumps. Initially, water requirements would be significant for the first five months as the site is prepared and rough grading conducted. During grading, water usage would be between 5 million and 10 million gallons per day (gpd), five days per week for a total period of 22 days per month for five months (or 110 days). Under the above assumptions, between approximately 7,000 and 14,000 gallons per minute (gpm) of water would be required daily from seven wells to support initial construction activities. This scenario was modeled by Environmental Simulations Inc. to evaluate pumping effects on groundwater levels (ENSR, March 2008).

Soil & Water Table 4
Proposed Annual Construction Water Demands

Average Daily Use (gallons)	Maximum Daily Use (gallons)	Water Supply Source	Delivery Method
1.6 million (5 AF)	10 million (30.7 AF)	Groundwater	Existing Onsite Wells

Source: BS 2008a

Following the initial five-month grading period, water would be used primarily for dust suppression and used in the construction of the solar field, power block and other site buildings. This site construction water use is expected to consume between 10,000 and 400,000 gpd for the remaining 22 months.

Operations Water Use

BSEP proposes to use onsite groundwater for project process needs. Plant processes are estimated to require an annual use of 1,600 acre-feet (AF). Groundwater would also provide the backup water supply. The onsite well field would include enough wells for redundancy should one or more of the onsite wells fail.

A raw water storage tank with a capacity of 2,840,000 gallons capacity would hold 2,480,000 gallons of water for plant operations (a water supply sufficient to cover an 18-hour interruption) and 360,000 gallons of raw water dedicated to the plant’s fire protection water system. The groundwater would be treated with a biocide (sodium hypochlorite) prior to storage. There also would be a treated water tank with a capacity of 2,350,000 gallons for raw make-up water in the cooling towers and as support for domestic water use and quench water. Plant process water would be treated via ion exchange to reduce scale-forming concentrations entering the cooling water system. In addition, a 150,000-gallon tank would be utilized to store de-mineralized water, and an 80,000-gallon capacity storage tank would be used for neutralization of water treatment wastewater.

WASTEWATER

Wastewater would be segregated in two separate collection systems, one for industrial streams (including the cooling tower blowdown and raw water treatment effluent) and the other for sanitary waste. The industrial system would collect wastewater from the Solar Steam Generator (SSG) and demineralization system and deliver it to the cooling tower basin. As discussed below, the cooling tower blowdown would be piped to onsite evaporation pond(s) for dewatering and the residual solids would remain in the pond(s) for the duration of the power plant life. If necessary for pond maintenance reasons, any solids removed from the pond(s) would be shipped to an appropriate offsite landfill. Wastewater sources include the following:

- Circulating water system blowdown,
- SSG blowdown,
- Demineralization system wastewater,
- Chemical feed area drains, and
- General plant drains.

The project's sanitary system would collect wastewater from sanitary facilities such as sinks and toilets, and the waste stream would be sent to an onsite sanitary waste disposal system.

Sanitary Wastewater (septic)

The proposed sanitary wastewater system would collect wastewater from sinks, toilets, and other sanitary facilities and discharge those fluids to an onsite septic system.

Process Wastewater

Initially, BSEP proposed to use three double-lined evaporation ponds, each with a nominal surface area of 8.3 acres, for a total of 25 acres. Subsequent to submittal of the AFC, BESP redesigned the three evaporation ponds to have a nominal surface area of 40 acres (WorleyParsons, March 2009). The ponds would be designed in accordance with Lahontan Regional Water Quality Control Board (LRWQCB) requirements. Multiple ponds are planned to allow plant operations to continue in the event that a pond needs to be taken out of service for maintenance. The applicant believes that each pond would have sufficient surface area to exceed the evaporation rate required to discharge cooling tower blowdown at maximum design and annual average design rates (BS 2008a). Pond depth is designed to be sufficient to accommodate and submerge residual solids for the life of the power plant. The pond liner system is designed to consist of a 60 mil high density polyethylene (HDPE) inner liner and a 50 mil HDPE outer liner. A synthetic drainage net, utilized as part of the leachate collection and removal system (LCRS), would be installed between the liners. A sand layer would cover the liner system, and sloped pond sections would have both sand and riprap layers covering the liner.

Evaporation pond monitoring would be required to detect the presence of liquid and/or constituents of concern emanating from the ponds (BS 2008a). The leak detection monitoring program for the facility consists of monitoring the LCRS, lysimeters, and monitoring wells for the presence of liquid and/or constituents of concern. The LCRS would be monitored to detect accidental liner failure. BSEP proposes to use several existing onsite water supply wells to detect groundwater impacts from accidental pond discharge. Constituents of concern would include chloride, sodium, sulfate, TDS, biphenyl, diphenyl oxide, potassium, selenium, and phosphate (BS 2008a).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

This section provides an evaluation of the expected direct, indirect, and cumulative impacts to soil and water resources caused by project construction, operation, and maintenance. Staff's environmental impact analysis consists of a brief description of the potential effect, an analysis of the relevant facts, and application of threshold criteria for significance to the facts. If mitigation is warranted, staff provides a summary of the applicant's proposed mitigation and a discussion of the adequacy of the proposed mitigation. If necessary, staff presents additional or alternative mitigation measures and refers to specific conditions of certification related to a potential impact and the required mitigation measures. Mitigation reduces potentially significant environmental impacts to less than significant.

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Impacts leading to soil erosion, flooding or depletion or degradation of water resources, are among those that staff believes could be most potentially significant associated with the proposed project. The significance thresholds for soil and water resources are discussed below.

Staff evaluated the potential impacts to soil and water resources including the effects of construction and operation activities that could result in erosion of soils, the deposition of sediments into surface waters and/or the contamination of either groundwater or surface water. Staff also evaluated the potential of the project's proposed water use to cause a significant depletion or degradation of local and regional water resources.

To evaluate if significant impacts to soil or water resources would occur, staff assessed:

- Whether the project would violate water quality standards or waste discharge requirements.
- Whether the project substantially depletes groundwater supplies or interferes with groundwater recharge such that there is a net deficit in aquifer volume or lowering of the local groundwater table level. For example, increase water level drawdown in nearby pre-existing wells to a level that fails to support permitted existing or planned land uses.
- Whether the project substantially alters existing site or area drainage patterns, including the alteration of stream or river courses, or substantially increases the rate or amount of surface runoff in a manner that results in on- or off-site flooding or substantial erosion or siltation.

- Whether the project would create or contribute runoff water that exceeds existing or planned storm water-drainage system capacity or provides substantial additional sources of polluted runoff.
- Whether the project would place structures within a 100-year flood hazard area and impede or redirect flood flows.
- Whether the project would lower groundwater levels such that protected species or habitats are affected.
- Whether the project would substantially degrade surface water or groundwater quality.

DIRECT/INDIRECT IMPACTS AND MITIGATION

The direct and indirect impact and mitigation discussion below discusses environmental impacts related to BSEP construction and operation. For each potential impact, staff briefly describes the potential effect and applies the threshold criteria for significance to the facts. If mitigation is warranted, staff provides a summary of the applicant's proposed mitigation and assesses its adequacy to reduce potential impacts to less than significant. In the absence of an applicant-proposed mitigation, or if the proposed mitigation is inadequate to reduce potential impacts to less than significant, staff mitigation measures are recommended. Implementation of staff-recommended measures is ensured through adopted specific conditions of certification.

Project Water Needs

BSEP proposes to use groundwater obtained from onsite wells equipped with temporary pumps to support site prewatering, grading and normal construction activities (e.g., soil compaction, mixing concrete, dust control). Project construction is expected to begin in the third quarter of 2009 and take approximately 26 months for completion. Commercial operation is expected to commence during the third quarter of 2011.
Initially, water demand for the project would be significant through the first five months of site preparation and rough grading. During initial grading, water usage would be between 5 million and 10 million gallons per day (gpd), five days per week for a total period of 22 days per month for five months or 110 days. According to the AFC, this initial grading could consume as much as 1.1 billion gallons or approximately 3,376AF. The AFC indicated that the silt content of site soils is approximately 7.5%. Staff has determined that the silt content in site soils ranges between 11% and 65%. Using a conservative estimate of 15% silt, staff estimates that the initial construction water use could exceed 6,752 AF. Following the five-month long initial grading period, water use is expected to decrease to a rate of approximately 400,000 gpd for a period of 21 months or 462 days. According to the AFC, this decreased construction water use could consume as much as approximately 185 million gallons or 567 AF. Combined, the volume of water used for construction of the BSEP could approach 7,319 AF over a 26-month period.

Actual project operations are planned to begin about 21-months after site grading and preparation. BSEP proposes to use a wet cooling tower for power plant cooling. Water for cooling tower makeup, process water makeup, and other industrial uses such as mirror washing would be supplied from selected onsite groundwater wells. Water from the onsite wells also would be used to supply potable water for employees (e.g., showers, sinks, toilets). A water treatment system would be used to treat the groundwater pumped for domestic use. Four existing water supply wells (nos. 41, 42, 49 and 63), would be used to supply water for the operation of the project. The four existing wells are located in the central and southwestern portion of the proposed plant site, and would be used on a rotating basis. When not in use, the offline wells would provide backup for each other in the event of outages or maintenance. Pumping test data provided by ENSR has shown water supply wells on the plant site have the capacity to meet BSEPwater supply requirements (BS 2008a). The well test results indicated the four wells can support the required 4,050 gpm maximum estimated pumping during project operations.

At the end of the 26-month construction period, project operations are expected to use at most 1,600 AFY of groundwater of which about 8 AFY (5 gpm) would be used for plant personnel's domestic supply needs.

ENSR estimated water usage during the months of April through September to average between 1,100 to 1,900 gpm. During the winter months of October through March, the flow rate is significantly reduced to between 34 gpm (December) and 731 gpm (October). The peak flow rate expected is approximately 4,000 gpm; the average flow rate for the entire year is about 990 gpm. These flow rate estimates are conservative since they do not take into account shutdown periods for facility maintenance (BS 2008a).

Potable water demands during construction would be minimal. The applicant proposes to use bottled water to supply drinking water for the construction workforce. Portable facilities would be used for sanitary needs and operate without water. Staff concludes that there would not be significant adverse environmental impacts associated with this potable water supply.

Impacts to Groundwater

Staff analyzed the project's proposed use of groundwater to determine if this water use would degrade local or regional surface water or groundwater supplies. Saint-Armand (1991) suggested that "farming had so lowered the water table that brackish water from Koehn Dry Lake may migrate westward into the pumping depression near Cantil…" Similarly, Koehler (1977), indicated that "because the groundwater gradient is from Koehn Lake toward the pumping depression (in the project site vicinity), saline water under Koehn Lake poses a potential threat to the fresh water supply." ENSR (March, 2008a; October 2008, and December 2008), summarized groundwater TDS concentrations inferred from well-water samples collected during the periods from 1953-1958, 1976-1978; and 1999-2007 and concluded water quality has remained relatively stable for wells located southwest of Koehn Lake (BS 2008a, Appendix J.4). Although there have been substantial historical changes in groundwater extraction rates and inferred groundwater-flow directions, ENSR (October 2008) concluded the relatively recent TDS concentration distribution (1999-2007) is similar to historical conditions (1953-1958). They concluded the historical pumping influence on TDS concentration distributions in groundwater has been limited, and the relatively high TDS concentrations observed beneath Koehn Lake have not been substantially mobilized or re-distributed by pumping practices. Similar to the sub-basin in general, they further indicate that groundwater quality has not changed substantially over time beneath the plant site.

However, staff's review of the same data indicated substantial uncertainty in spatial and temporal TDS concentration trends. TDS concentrations in samples from some referenced wells have varied by more than 80-percent over time, contributing to the overall uncertainty in actual groundwater quality conditions in time and space. ENSR attempted to explain this variation by stating that over time, the number of sampling locations has decreased substantially, and therefore the data set is smaller. ENSR further stated that the Koehn sub-basin wells typically have large screen intervals and, if combined with inconsistent sampling protocols between sampling events, those factors can result in substantial variability in water-sample chemistry. However, that explanation is not supported by the fact that samples collected at the same time from other wells did not have such variation, and therefore the inconsistent sampling protocol explanation does not appear to be viable. Koehn Lake is hydraulically connected to groundwater in the basin and is reportedly the only significant natural discharge feature in the Fremont Valley Basin. Should increased pumping draw down the water table and cause flow of saline groundwater from the Koehn Lake area towards the proposed water supply well field, there could be a significant impact to Basin water quality.

Three water samples were collected from onsite wells near the end of ENSR's (March 2008) pumping tests. The analytical results were summarized in Table 5.17-7 of the AFC (ENSR, March 2008a). The water quality appears to be generally similar to adjacent water supply well data and meets most State and Federal requirements for drinking water as follows:

- TDS concentrations are around 500 mg/L, which indicate it is a freshwater supply and a valuable drinking water resource in California.
- Chloride concentrations (15-18 mg/L) are low and below State Secondary Maximum Contaminant Levels (MCLs) for drinking water.
- Sulfate concentrations (110-120 mg/L) are also low and below State Secondary MCLs for drinking water.
- The Nitrate concentration is well below the State MCL of 10 mg/L for drinking water. The minor exceptions to the good water quality are reported concentrations for arsenic and manganese.
- Arsenic was reported in all the effluent samples at concentrations similar to what has been reported for the Koehn sub-basin (AFC). Although arsenic concentrations are above the EPA Region IX Preliminary Remediation Goal (PRG) for tap water, these concentrations are below the primary State and Federal MCL for Arsenic.
- Total manganese concentrations in one sample (57 µg/L) were slightly greater than the State and Federal Secondary MCL (BS 2008a, Table 5.17-7). The sample was unfiltered, and a filtered duplicate did not exceed the Secondary MCL suggesting suspended solids influenced the total results.
- With the exception of two organophosphorous pesticides, no organic chemicals in the water samples were detected at concentrations above their respective practical

quantitation limit (PQL). In samples from wells no. 43 and 63, dimethoate and fensulfothion were reported at very low estimated concentrations between the method detection limit (MDL) and PQL. While these compounds were detected above their MDL, the results are considered an estimate because the analytical laboratory was not able to accurately quantify the concentrations at these very low levels. MCLs have not been established for either dimethoate or fensulfothion for drinking water, although EPA Region IX has established a Preliminary Remediation Goal (PRG) for dimethoate (BS 2008a, Appendix J.4); the single reported value for dimethoate is below the EPA Region IX PRG for tap water.

Evaluation of laboratory analyses conducted on groundwater samples collected from onsite wells indicate the site groundwater is fresh and with minimal treatment, suitable for drinking.

The volume of groundwater stored in a basin can vary over time because of changes in water inflow and outflow. Groundwater storage and well water levels increase when inflow exceeds outflow. Conversely, groundwater storage and water levels decrease when inflow is less than outflow. Significant adverse impacts can occur when groundwater storage conditions are in a state of perpetual decline, including increased extraction costs, costs of well deepening or replacement, land subsidence, water quality degradation, and environmental impacts (DWR, 2003).

The Fremont Valley Groundwater Basin is divided into six sub-basins (BS 2008a, Figure 5.17-1), and the sub-basins are typically separated by faults that form partial barriers to groundwater movement (Bloyd 1967, Koehler 1977, Saint-Armand 1991). The proposed BSEP site is located in one of the six sub-basins (the Koehn sub-basin). Staff therefore assessed reported regional groundwater level trends and water budget conditions for the entire Fremont Valley Basin, as well as the relatively local conditions within the Koehn sub-basin.

Staff obtained well water level elevations from DWR, constructed select hydrographs and inserted the hydrographs into a map showing the Fremont Groundwater Basin and Koehn sub-basin (**Soil & Water-Figure 1**). The Koehn sub-basin generally coincides with the Koehn Lake area delineated in **Soil & Water-Figure 1**. Staff elected to show this area in-lieu of the Koehn sub-basin boundaries because it coincides with the study area reported by Koehler (1978), a key historical study of the Fremont Basin and substantially relied upon by the project applicant for their hydrogeologic assessment. The hydrographs plotted in **Soil & Water-Figure 1** were selected to represent:

1. Spatial variability across the Fremont Valley Basin and Koehn sub-basin;

2. The longest and most complete data sets;

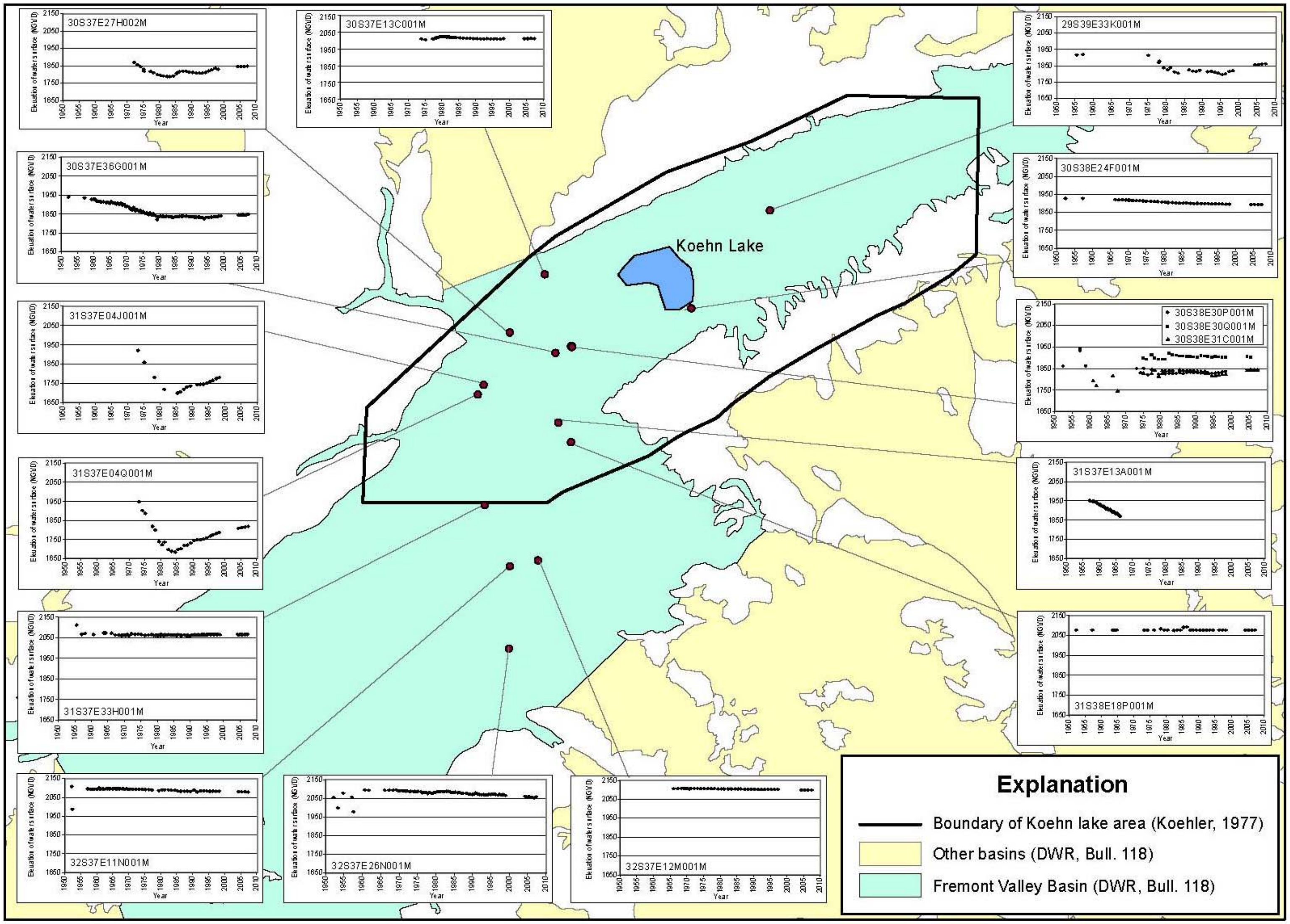
3. Observed variation in wells located relatively near to each other (30S38E30P001M, 30S38E30Q001M, 30S38E31C001M); and,

4. The relationships between water level recovery, well locations, and historical pumping centers.

Water levels trends show variable responses to pumping. Water level declines, generally first apparent in the1950s, accelerated during the 1970s because of increased agriculture production. Groundwater consumption in the Koehn Lake area dramatically decreased during the late 1980s and 1990s, and as a result water levels have been partially recovering for the past 10 to 15 years in most Koehn Lake area wells.

From the water level data shown in **Soil & Water- Figure 1**, staff prepared **Soil And Water Table 5**. **Soil And Water Table 5** shows historical maximum water levels, 2008 water levels, the calculated change between maximum and 2008 water levels, and the average annual water level trend during 1998-2008. The 1998-2008 period was selected because it represents water use conditions since the last substantial basin assessment reported by EarthSat (1997).

Soil & Water-Figure 1
Water Level Trends, Fremont Valley Basin



In 2008, water levels in all but one well shown on **Soil & Water Table 5** are from eight to 129 feet below their historical maximum values. Hence, water levels remain significantly lower than they were prior to groundwater consumption by agriculture during the 1970s and early 1980s. Since 1998, water levels in Koehn Lake area wells (see **Soil & Water-Figure 1**) show gradual increases ranging from 0.2 to almost 6 feet per year. The greatest observed water level increases are observed in wells located within historical pumping centers (former agricultural areas). In contrast, water levels in wells south of the Koehn Lake sub-basin indicate gradual long-term declines averaging -0.01 to -1.6 feet per year since 1998. These observations are consistent with reduced pumping and subsequent groundwater storage recovery in some parts of the basin, and continued pumping and storage declines in other parts of the basin.

Soil & Water Table 5
Reported Fremont Valley Basin Water Levels

Well Number	**Historical Maximum GWE**		**2008 GWE**		**Change** (2008 Maximum)	**1998-2008 Trend** (ft/yr)
	Year	Elevation	*Year*	Elevation		
KOEHN SUB-BASIN						
29S39E33K001M	*1958*	1919	*2008*	1863	-56	5.1
30S37E13C001M	*1978*	2025	*2008*	2011	-14	0.2
30S37E27H002M	*1973*	1869	*2008*	1849	-20	1.7
30S37E36G001M	*1929*	1950	*2008*	1847	-103	1.0
30S38E24F001M	*1953*	1928	*2008*	1893	-35	-0.3
30S38E30P001M	*1958*	1933	*2008*	1844	-89	1.0
30S38E30Q001M	*1958*	1942	*2008*	1901	-41	0.1
30S38E31C001M	*1986*	1844	*2008*	1844	0	2.4
31S37E04J001M*	*1974*	1920	*1999*	1779	---	---
31S37E04Q001M*	*1974*	1948	*2008*	1819	-129	3.8
31S37E13A001M	*1958*	1951	*1967*	1870	---	---
CALIFORNIA CITY AND CHAFFEE SUB-BASINS						
31S37E33H001M	*1956*	2110	*2008*	2064	-46	-0.1
31S38E18P001M	*1917*	2085	*2008*	2077	-8	-0.01
32S37E11N001M	*1953*	2107	*2008*	2078	-29	-0.4
32S37E12M001M	*1970*	2108	*2008*	2100	-8	-0.2
32S37E26N001M	*1970*	2095	*2008*	2060	-35	-1.6

Data from: DWR, Groundwater Level Data, March 2009
* On-site well

In their Conceptual Hydrogeologic Model, ENSR (March, 2008) estimated a water budget for the Fremont Valley groundwater basin. There is uncertainty in the water budget components, and assumptions employed in previous budget assessments have provided variable results. Staff developed a water budget approach, reviewed and summarized previous budget study results, and assessed the results to provide insight into the above water level trends.

Soil & Water- FIGURE 2 summarizes the primary water inflow and outflow components in the Fremont Valley Groundwater Basin. Conservation of mass requires inflows and outflows balance as represented by Equation (1):

$$\mathbf{R + GW_i = W + LD + GW_o + \Delta S} \qquad (1);$$

where,

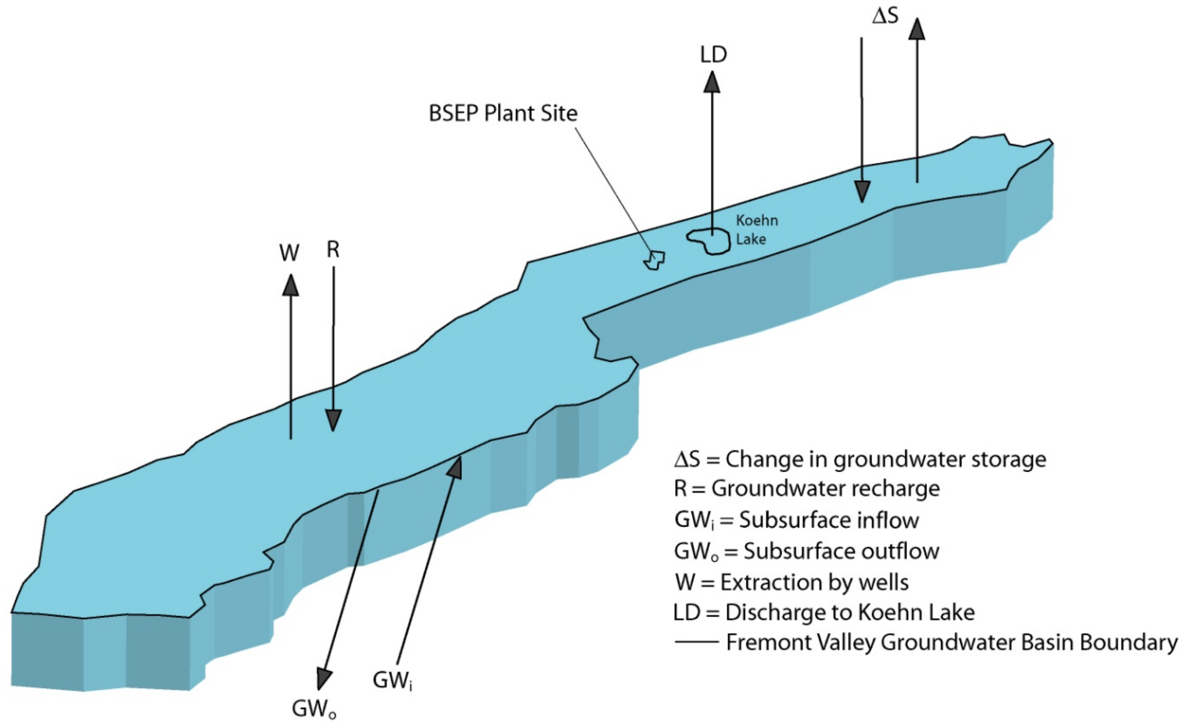
- Δ**S** is the change in groundwater storage;
- **R** is groundwater **recharge** from all possible sources (the net result of percolation of rainfall, infiltration of surface water runoff from surrounding mountains and foothills, applied irrigation water, and so forth, less the consumptive use of water by evaporation, native plants and agriculture);
- $\mathbf{GW_i}$ is **subsurface** inflow from the adjoining Antelope Valley Groundwater Basin;
- $\mathbf{GW_o}$ is **subsurface** outflow to the adjoining Antelope Valley Groundwater Basin;
- **W** is **groundwater** extraction by Fremont Valley wells; and,
- **LD** is **groundwater** discharge to Koehn Lake.

Equation (1) is rearranged to solve for Δ**S**:

$$\mathbf{\Delta S = R + GW_i - GW_o - W - LD} \qquad (2).$$

A positive value for Δ**S** indicates inflow is greater than outflow, and storage and water levels increase. Conversely, a negative value for Δ**S** indicates inflow is less than outflow, and storage and water levels decrease.

Soil & Water- Figure 2
Conceptual Fremont Valley Basin Water Budget.



In the Fremont Valley Basin, under pre- and early development conditions, groundwater extraction by wells and the long-term groundwater storage changes was zero. Stable storage conditions are represented by long-term stable (constant) water levels and gradients. Koehn Lake is the only significant natural discharge feature in the basin, and any other subsurface outflows were negligible. Hence, under pre- and early development conditions Equation (1) is reduced and re-arranged to represent a balance between inflows and outflows:

$$\mathbf{R + GW_i = LD} \qquad (3).$$

GSi/water (1993) calculated the potential amount of groundwater discharge into Koehn Lake in the absence of pumping wells at about 18,000 AF/yr. The only significant subsurface inflow was from the Antelope Valley Basin, which reportedly occurs through a gap in the bedrock located southeast of California City. Durbin (1978) estimated this flow at a rate of about 1,000 AF/yr, and Leighton and Phillips (2003) later refined the estimate to consider water level declines occurring in both the Antelope Valley and Fremont Valley basins. Leighton and Phillips (2003) concluded the inflow from Antelope Valley decreased from about 500 AF/yr in 1958 to 200 AF/yr by 1995. These studies suggest long-term, average annual Fremont Valley recharge under pre- and early development conditions ranged from about 17,000 to 17,500 AF/yr, which is at the lower end of the broad range of average annual recharge rates estimated by GSi/water (1993) (4,200 to 42,000 AF/yr).

In the Fremont Valley Basin, the number of wells and extraction rates increased over time and consumed ever-increasing quantities of groundwater. When outflow eventually exceeded recharge, the storage volume and well water levels declined. **Soil & Water Table 6** summarizes the limited available water budget information provided by previous hydrologic studies for these time periods.

Soil & Water Table 6
Fremont Valley Basin Water Budget (All Units In AF/yr).

	ΔS	R	$GW_i - GW_o$	W	LD
Early Development	0	17,000 to 17,500 [a]	1000 [b] to 500 [c]	0	18,000 [d]
1958-1976	---	---	400 [c]	---	---
1977-1984	---	---	300 [c]	---	---
1985-1997	10,400 to 15,300 [e]	4,200 to 42,000 [d]	200 [f]	---	---
1998-2007	---	4,200 to 42,000 [d]	100 [f]	---	2,800 to 3,000 [g]

a) Calculated using Equation (3).
b) Durbin (1978).
c) Leighton and Phillips (2003).
d) GSi/water (1993).
e) EarthSat (1997).
f) Projected from simulated annual trend reported by Leighton and Phillips (2003).
g) ENSR (2008).

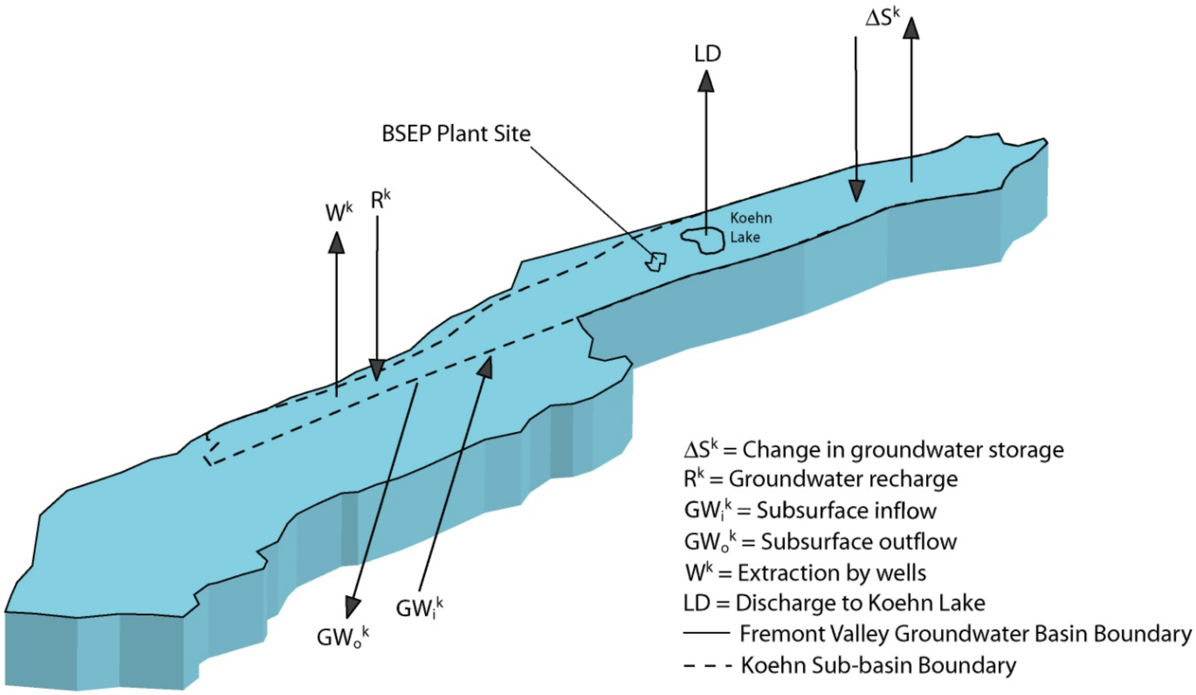
Determination of the annual basin recharge is uncertain, and inflow from the Antelope Valley Basin has been declining with time. Water budget estimates seem to indicate that basin-wide groundwater storage began to increase during the mid- 1980's. The water level data reported in **Soil & Water Table 8** indicate storage increases continue in some parts of the basin. Reliable groundwater extraction rates are not readily available for the basin, and storage changes during the 1998-2007 periods have not been estimated.

A budget approach also applies to the Koehn sub-basin (**Soil & Water Figure 3**):

$$\Delta S^k = R^k + GW^k{}_i - GW^k{}_o - W^k - LD \qquad (4).$$

The terms in Equation (4) are similar to Equation (1); however, the components are distinguished by a superscript "k" to clarify they apply specifically to the Koehn sub-basin. The primary outflow is to Koehn Lake, and conceivably water could flow in or out between the adjoining Oak Creek, Chaffee, and California City sub-basins. Under pre- and early development conditions, any subsurface flow was away from these sub-basins into the Koehn sub-basin and discharged to Koehn Lake. However, with variable well locations and groundwater consumption the gradients between sub-basins would change, and conceivably if drawdowns were great enough, gradients could reverse between sub-basins resulting in a net loss of groundwater from the Koehn sub-basin.

Soil & Water Figure 3
Conceptual Koehn Sub-Basin Water Budget.



In the Koehn sub-basin, the number of wells and extraction rates increased with time, consuming greater quantities of groundwater. Several investigations estimated the historical changes in groundwater storage. Koehler (1977) utilized observed water level changes in wells during the period 1958-1976 to estimate the storage change within an area generally coinciding with the Koehn sub-basin. EarthSat (1997) also utilized water level changes to estimate storage changes during the period 1985-1997 for seven Fremont Valley Basin subareas; the combined area of five subareas generally coincide with the Koehn sub-basin. ENSR (2008) reported the results from a numerical groundwater-flow model of the Koehn sub-basin, and the model simulated annual storage changes during the period 1958-2007.

Soil & Water Table 7 summarizes Koehn sub-basin water budget estimates. For the past two decades, groundwater storage has generally increased by about 10,000 to 15,000 AF/yr. The Koehn sub-basin is 146,500 acres in area (Bloyd, 1967), and if applied uniformly, this storage change corresponds to average annual water level increase ranging from about 0.07 to 0.1 foot per acre per year. Water level increases of this magnitude are consistent with observed trends depicted in **Soil & Water- Figure 1**, with the exception of those wells located nearest the major historical pumping centers.

Soil & Water Table 7
Water Budget Estimates For The Koehn Sub-Basin (All Units In AF/yr).

	Source	ΔS^k	R^k	$GW^k_i - GW^k_o$	W^k	LD^k
Early Development	Equation (4)	0	---	---	0	18,000
1958-1976	Koehler (1977)	-21,800	700	9,500	32,000	--- [c]
	ENSR (2008)	-19,800	15,700	1,700	31,100	6,100
1977-1984	ENSR (2008)	-23,400	15,700	1,700	40,800	0
1985-1997	EarthSat (1997)	9,700 to 14,800	---	---	---	---
	ENSR (2008)	-3,400	15,700	1,700	20,800	0
1998-2007	ENSR (2008)	12,500	15,700	1,700	4,900	0

In the Koehn sub-basin, increasing water levels are the result of recharge from infiltration of rainfall runoff, groundwater inflow from adjacent sub-basins, and subsurface inflows partially re-filling the depression created by historic pumping. There is uncertainty in the relative contribution of these three components, and how their contributions may change as a result of future pumping increases. Additional analysis is needed to quantify recharge, groundwater inflow, and water level transients to reliably assess basin sensitivity to pumping and potential impacts from increased groundwater consumption.

Analysis of potential changes in groundwater levels from project pumping was necessary to evaluate possible impacts on other wells, water users, and the primary potable water supply for the Fremont Valley. Drawdown or water level declines due to groundwater pumping can significantly impact nearby wells. Interference or drawdown can result in increased pumping lifts, extraction costs, and declines in well productivity. Storage depletion can lead to land subsidence, water quality degradation, and loss of a potable water supply. Mitigation of these impacts could require costly modifications including the cost of lowering pumps, deepening wells, and ultimately securing an alternative water supply.

The magnitude of drawdown impact is controlled by five factors: (1) the rate of pumping; (2) the duration of pumping; (3) the depth of the well screens (water-intake depth of well); (4) aquifer parameters; and (5) aquifer boundary conditions. Aquifer parameters, such as specific yield and hydraulic conductivity, are determined by the layering and thickness of the primary water bearing materials such as gravel and sand. The composition and flow characteristics of an aquifer can vary widely. This PSA utilized a project pumping induced drawdown of 5 feet or more in any groundwater well as a substantial groundwater depletion potentially requiring mitigation.

To evaluate potential project-related pumping impacts, the applicant developed a two-dimensional groundwater-flow model of the Koehn sub-basin. Staff reviewed the model and concluded it appears properly constructed using an accepted computer code. The aquifer parameter values and boundary conditions specified in the model are generally consistent with the conceptual groundwater system described in previous reports. However, staff's review of published modeling studies and data provided by the project applicant indicate two boundary conditions may be improperly specified (Antelope Valley inflow from the Fremont Valley Basin and the timing and magnitude of discharge to Koehn Lake), and the model may neglect an important historical recharge process (agricultural return flows). Additionally, calibration constraints are not fully explained and staff implementation of the model found some simulations failed to converge (after staff adjusted the numerical solver package, the problem simulations converged). All model simulations appear to meet acceptable mass balance errors and head closure criterion. At the request of staff, the applicant reported additional model simulations that consider the sensitivity of model results to uncertainty in aquifer parameters (hydraulic conductivity and storage coefficient), fault hydraulic characteristics, and recharge. The sensitivity test results provided a plausible range in Koehn sub-basin responses to project groundwater pumping. Staff's evaluation and conclusions regarding the model are presented in **SOIL and WATER-Appendix B**.

Environmental Simulations, Inc. (ENSR, March 2008a) modeled the 5-month construction water use scenario to assess pumping effects assuming continuous extraction during an eight-hour day, five days per week for a total of 110 non-consecutive days (BS 2008a). Under these assumptions, ENSR determined that between about 7,000 and 14,000 gallons per minute (gpm) of water would be required daily from seven wells to support initial construction activities. The groundwater model simulation assumed seven wells pump continuously during the five- month period at about 4 million to 80 million gpd (daily rates adjusted for continuous pumping). Based on this modeling, ENSR determined that the pumping would not significantly impact offsite water supply wells within a one-mile radius of the plant site, as only two offsite wells are expected to experience five feet of drawdown at the end of the five months period. Furthermore, the drawdown is considered a short-term effect, and the downward water level trend is expected to cease and reverse itself after water usage rates decrease significantly during the remainder of project construction. Following the initial grading period, groundwater usage would drop dramatically with daily rates ranging from 10,000 to 400,000 gpd. The AFC concluded that water usage and effects on surrounding wells and groundwater quality would be less than significant.

Staff reviewed maps provided in the AFC that show maximum simulated pumping drawdown during the site-grading period. The maps indicate 2 single family wells located northwest of the property would be impacted by about 5-feet of drawdown, and because of uncertain aquifer conditions (semi-confined, unconfined, or unconfined with delayed yield), these results are considered minimum drawdowns and staff concluded short-term drawdown could be greater.

For project operations, 1,600 AFY of pumping was simulated for a continuous 30-year period (ENSR, March 2008b). Later submittals by ENSR (October, 2008 and December, 2008) reported the sensitivity of model simulation results to aquifer parameters (specific yield and hydraulic conductivity), fault hydraulic characteristic, and recharge.

The model results are reported in maps showing simulated drawdown contours and water supply well locations. Staff summarized the results in **Soil & Water Table 8** by totaling the number of wells impacted by water level declines of 5 feet or more. ENSR's maps and the results in **Soil & Water Table 8** indicate a substantial number of public and private wells are potentially impacted by project groundwater use. The results in **Soil & Water Table 8** are considered minimum impacts because model simulations do not consider residual drawdowns from site construction water use and their cumulative effect on long-term drawdown.

Soil and Water Table 8
Summary of Impacts Projected by Calibrated Model and Sensitivity to Select Parameters and Stresses

Model Run	Mapped Wells Having Simulated Drawdown Greater Than or Equal to 5 feet After 30 Years of Pumpage						Drawdown Less than 5 Feet	Total [a]
	Agricultural	Industrial	Multiple Family	Single Family	Municipal	Subtotal		
Calibrated Model	1	3	1	14	1	20	9	29
½ specific yield	1	3	1	13	0	18	11	29
2 specific yield	0	3	1	3	0	7	22	29
½ hydraulic conductivity	1	3	1	14	0	19	10	29
2 hydraulic conductivity	0	3	1	3	0	7	22	29
Recharge = 10,000 af/yr	0	3 [b]	1	12 [b]	0	16	13	29
Recharge = 25,000 af/yr	0	3 [b]	1	8 [b]	0	12	17	29
Remove Fault [c]	0	5	1	5	1	12	17	29
Remove Zone 2 [d]	1	3	1	12	0	17	12	29

a: Total number of wells shown within the reported map extent – not necessarily the total number of wells in the Koehn sub-basin.
b: The maps prepared by ENSR have different extents, and as a result wells visible on one map may not be visible on another. We therefore estimated the simulated impacts by projecting the contours into the excluded areas where previous maps showed a well was located.
c: Although not specifically stated, we assumed only the Cantil Fault was removed from the model per Table 4.1 (ENSR, March 2008b).
d: Although not specifically stated, we assumed Zone 2 refers to the Randsburg-Mojave Fault per Table 4.1 (ENSR, March 2008b),

In terms of the number of wells affected, the 30-year project simulation using the calibrated model resulted in the greatest number of impacted wells (20). Model results indicate that 20 wells located within a distance of about 4 miles of the simulated pumping well (Well 48) are reduced by 5 feet or more after 30 years of pumping relative to expected conditions without the project. **Soil and Water Table 8** considers only the number of wells affected by 5 feet or more of drawdown, and does not reflect relative differences in the magnitude of drawdown at different wells.

Because groundwater levels in the immediate site vicinity appear to be rising, simulated drawdown corresponds to a reduction in the rate of water rise but not necessarily a decrease in absolute water level elevation relative to present-day conditions. For example, a drawdown of 5-feet indicates that in 30-years the projected water level would be 5-feet lower than without the proposed project. Groundwater storage and water levels in the immediate site vicinity could continue to increase with time but at a reduced rate.

Construction Wastewater

During construction, groundwater would be used for one-time hydrostatic testing of pipelines and pressure vessels. According to the applicant (BS 2008a), this water would be reused to the extent possible and then discharged as wastewater. In addition, a small amount of groundwater is needed for equipment washing. Improper handling or containment of construction wastewater could cause a broader dispersion of contaminants to soil, groundwater, or surface water. The discharge of any wastewater during construction would be required to comply with applicable Basin-wide waste discharge regulations adopted by the LRWQCB.

Operation Wastewater

Wastewater generated from the project operation includes cooling tower blow down, sanitary wastewater, and storm water. The applicant proposes two separate wastewater-collection systems for BSEP. The water-balance diagrams provided in the AFC (BS 2008a), show the expected wastewater streams and flow rates for the project under summer (representing peak usage) and annualized conditions.

The first wastewater collection system is the process waste water system. The process waste water system collects all onsite waste water generated from operation of the plant. Process water wastes, including cooling tower blowdown and waste streams from the neutralization tank would be disposed to lined, onsite evaporation ponds. An estimated peak summer discharge for all process wastewater to the evaporation ponds is estimated at 563 gpm, with an annualized average for the project of 462 gpm. The ponds would be sized to retain all solids generated during the life of the plant. However, if required for maintenance, dewatered residues from the ponds would be characterized and, as appropriate, sent to an appropriate offsite landfill as non-hazardous waste. The discharge to the ponds is estimated to be 710 tons annually, for a total of 21,000 tons at the end of the 30-year project.

Initially, BSEP proposed to use three double-lined evaporation ponds, each with a nominal surface area of 8.3 acres, for a total of 25 acres. Rather than constructing one 25-acre pond, multiple ponds were planned to allow plant operations to continue in the

event that one of the ponds would need to be taken out of service. According to the AFC, each pond would be designed to have enough surface area so that the evaporation rate exceeds the process wastewater and cooling tower blowdown rate at peak design conditions and at annual average conditions.Subsequent to submittal of the AFC, BESP redesigned the three evaporation ponds to have a nominal surface area of 40 acres (WorleyParsons, March 2009).
The applicant's water balance for typical annual conditions shows a wastewater rate to the evaporation ponds of 471 gpm (BS 2008a, Section 2, Figure 2-13). This consists primarily of cooling tower blowdown and wastewater from water treatment. BSEP plans to operate at an annual 26.5% capacity factor (94% capacity factor during daylight periods). Adjusting wastewater flow to a 24-hour operating basis, flow to the evaporation ponds would be 125 gpm (471 gpm x 26.5%). In this scenario, all three wastewater disposal ponds, as designed, would have to operate for the entire year to accommodate this flow.

In order for evaporation of the wastewater to offset the expected effluent flow into the proposed evaporation ponds, the evaporation rate would have to be 97 inches per year. Using evaporation pan data coupled with designed pond size and expected effluent salt concentration, the corrected evaporation rate for the project area would be approximately 72 inches per year (See **Soil and Water-Appendix D**).

Based on these corrected evaporation values, the disposal ponds, as designed, are inadequately sized to contain expected flow and at least one additional pond would likely be required. To contain the expected flows, given the corrected evaporation values, staff determined that 43.5 acres of pond area would be required as opposed to the 25 acres identified in the AFC. If water use in the power plant is greater than that described in the water balance presented in the AFC, then additional pond area would be required. Also, BSEP stated they would construct another pond (in addition to those three proposed to hold waste water) to be used for dilution of potentially toxic salinity concentrations in the evaporation ponds. With this additional pond, the nominal evaporation pond surface area would be on the order of 58 acres.

To comply with LRWQCB requirements for discharge of process wastewater to land (ponds), a Draft Report Of Waste Discharge (ROWD) prepared by ENSR for BSEP was received by LRWQCB on May 21, 2008. On January 12, 2009, LRWQCB sent a response letter to Beacon Solar, LLC, commenting on the Draft ROWD and specifying numerous deficiencies in the ROWD.

Some of the outstanding deficiencies are as follows:

- Incomplete waste characterization
- Lack of percolation tests in the disposal field area
- Lack of a topographic map showing various site features
- Lack of a map showing impermeable surfaces that would contribute to storm water runoff
- No depiction of storm water runoff controls adequate for design storm events
- Lack of lithologic profiles showing site subsurface conditions

- Need to submit a revision of the General Arrangement Site Plan to show the wastewater discharge pipeline alignment, and points of discharge
- Need to submit a parcel map showing Assessor's Parcel Numbers, parcel boundaries, outlines of evaporation ponds, Land Treatment Unit (LTU), power block, solar arrays and other ancillary facilities
- Need to provide wastewater process flow diagram additions
- Need to provide evaporation ponds elevations and dimensions
- Need to provide detailed grading and drainage design for evaporation ponds
- Need to provide hydrologic calculations supporting the grading and drainage plans for the evaporation ponds
- Need to provide a narrative and details of storm water BMPs for the 25-year, 24 hour storm event
- Need to provide a narrative that the facilities will be protected from a 100-year, 24-hour storm event
- Need to evaluate water quality impact to blue line streams and other drainages
- Need to submit civil engineering drawings showing the grading and drainage plan for the evaporation ponds and LTU
- Need to submit grading and drainage plans incorporating the proposed measures to control runoff from the design storms
- Need to submit hydrologic calculations supporting the above grading and drainage plans
- Need to provide a narrative on site climatology, including evaporation and precipitation rates
- Need to provide waste descriptions, discharge volumes and discharge rates for all waste materials discharged to the evaporation ponds
- Need to provide a map showing the locations of the evaporation ponds, LTU and conveyance piping relative to the locations of Holocene seismic features and Special Study Zones
- Need to submit a revision of the Land Farm Unit Preliminary Design, Operation and Maintenance Plan
- Need toprovide greater detail of the Detection Monitoring Program showing an increase in groundwater monitoring frequency and a description of the statistical analysis approach to be used to determine if a release has occurred
- Need to submit closure, post-closure and corrective plans for the evaporation ponds and LTU prepared in separate binders
- Need to provide Financial Assurance Plans provided separately for the above plans
- Need to provide cost estimates for each of the above plans

- Nee dto conduct an analysis of the ROWD's compliance with the requirements of the Lahontan Regional Board Basin Plan and SWRCB Resolution 68-16, Anti-Degradation Policy.

As of March 18, 2009, the complete ROWD has not been received by LRWQCB. Staff is awaiting the applicant's submittal of a complete ROWD so that the potential impacts due to the proposed evaporation ponds can be analyzed.

The second proposed wastewater-collection system is the sanitary system. The sanitary system would collect wastewater from sinks, toilets, and other sanitary facilities for discharge to an onsite septic sewer system and leach field. Design and construction of the on-site waste disposal system would be completed in accordance with Kern County Environmental Health Services Department, Sewage Disposal by Individual Soil Absorption Systems requirements. In order to comply with Kern County on-site sewage disposal requirements, staff recommends that the sanitary wastewater system be constructed in accordance with condition of certification **SOIL & WATER – 1.**

Staff believes there would be no significant water or soil related impacts from wastewater discharge if the applicant complies with Conditions of Certification **SOIL&WATER- 1.**

Soil Erosion Potential by Water and Wind

During Construction

Construction activities can adversely affect soil resources including increased soil erosion, soil compaction, loss of soil productivity, and disturbance of soils crucial for supporting vegetation and water dependant habitats. Activities that expose and disturb the soil leave soil particles vulnerable to detachment by wind and water. Soil erosion results in the loss of topsoil and increased sediment loading to nearby receiving waters. The magnitude, extent, and duration of those impacts would depend on several factors, including the proximity of the BSEP site to surface water, the soil types affected, and the method, duration, and time of year of construction activities. Prolonged periods of precipitation, or high intensity and short duration runoff events coupled with earth disturbance activities can result in on-site erosion. In addition, high winds during grading and excavation activities can result in wind borne erosion leading to increased particulate emissions that adversely affect air quality.

The BSEP site would be subject to wind and water erosion during construction. Project construction would be completed over a 26-month period (BS 2008a). The total earth movement would be significant, with up to 20 feet of cuts and fills amounting to approximately 5,200,000 cubic yards of soil being moved (BS 2008a). The earthwork would consist of primarily cut and fill grading with excavation for foundations and underground systems. In addition, Pine Tree Creek is proposed to be realigned around the southern and eastern sides of the property through an engineered diversion channel.

A draft project grading plan and SWPPP has been prepared by the applicant that includes Best Management Practices (BMPs) for wind and water erosion control during project construction. The implementation of appropriate erosion control measures would help conserve soil resources, maintain water quality, prevent accelerated soil loss, and protect air quality. The erosion and sedimentation control measures that the applicant would implement include: wetting the roads in active construction and laydown areas; controlling speed on unpaved surfaces; placing gravel in entrance ways; use of straw bales, silt fences, and earthen berms to control runoff; restoration of native plant communities by natural revegetation, seeding and transplanting, and application of soil bonding and weighting agents. Watering for fugitive particulate matter emission control during soil handling, bulldozing and grading is expected to maintain soil moisture (BS 2008a). During grading work, soil would also be stabilized by maintaining sufficient water content to make it resistant to weathering and erosion by wind and water. Silt fences would be placed at adequate spacing perpendicular to the drainage path and generally oriented in a northwest to southeast direction to trap sediment before it can migrate.

Given the low frequency of precipitation and storm water runoff, which historically does not reach the valley floor, BMPs implemented during construction should limit potential soil loss from water erosion caused by on-site precipitation events. As outlined in the preliminary DESCP, Best Management Practices (BMPs) would include temporary erosion control methods such as the use of crushed rock, silt fences and fiber rolls. The potential for soil loss by water erosion was estimated by ENSR (March 2008) for pre-development, construction, and post-development conditions. Under current conditions, the soil loss was estimated to be about one ton per year. As described above and in the DESCP, without implementation of control measures and BMPs, construction activities would increase the potential for soil loss. Estimated soil loss during the construction period is about 150 tons per year (ENSR). Although the expected infiltration rate at the site is rapid, BMPs would include the following:

- Local soil berms and a detention area would be constructed to contain storm water runoff.
- During site grading, clearing and grubbing would be confined to only those areas needed for facility construction as indicated in the conceptual grading plan.
- Temporary erosion controls including crushed rock, silt fences and fiber rolls would be used as needed to minimize erosion in active grading areas. Soil stockpiles would be covered prior to forecasted storm events and during windy conditions. Fiber rolls or gravel bags would be placed around the perimeter of the stockpiles to further minimize the potential for runoff.
- Additionally, water would be used to control dust and would be applied at a rate so as to minimize runoff.

BMPs would be applied and repaired as soon as erosion is evident and as soon as possible. Temporary erosion control measures would be implemented as needed to control erosion. Temporary sediment control materials would be maintained onsite throughout the life of the project to respond as needed to unforeseen rain or emergencies.

In the absence of proper BMPs and due to the soil type, the project earthwork could cause significant fugitive dust and erosion. As shown in **Soil and Water Table 2**, the predominant surface soil condition on the proposed BSEP site is fine to gravelly sand with a water erosion potential of slight to moderate. The surface textures of these gravelly areas have a slight potential for wind erosion and those areas with a finer component have a high potential for wind erosion (NRCS 2008). However, with implementation of BMPs identified by the applicant in the AFC and proposed in Condition of Certification **SOIL & WATER-2**, significant soil erosion impacts would be avoided. Overall, staff believes the applicant has identified a reasonable plan and sequence for implementing BMPs that would avoid significant adverse impacts. Staff concludes that through the proper application of BMPs as proposed by these conditions of certification, the impact to soil resources from water and wind erosion during construction would be reduced to a level that is less than significant.

Staff has reviewed the February 5, 2008 letter from the Department of the Army, Los Angeles District, Corps of Engineers indicating the BSEP is not subject to Corps jurisdiction under Section 404 of the Clean Water Act. However, it is not clear to staff if the jurisdictional determination includes linear facilities such as the gas pipeline. Staff recommends Condition of Certification **SOIL&WATER-3** which would require the applicant to assess potential impacts caused by the construction of the pipeline across areas subject to regulation by the Corps of Engineers. Condition of Certification **SOIL&WATER-3** also requires the applicant to verify that the pipeline would meet the requirements to ensure all water quality standards are met and the Streambed Alteration Agreement(s) which would determine whether the BSEP linear construction would substantially modify a stream and adversely affect fish and wildlife resources.

During Operation

The applicant has proposed permanent erosion control measures to mitigate potential soil related impacts from the operation of BSEP. During operations, areas not covered by foundations and paving would be treated with soil stabilizers. Staff is concerned that the soil stabilization treatments may cause a reduction in infiltration and requests that the BSEP describe potential impacts related to storm water runoff from treated soils, the durability of these soil stabilizers to withstand adverse weather conditions, and its susceptibility to vehicular traffic. These erosion control measures would be included in the general NPDES permit application required by staff in Condition of Certification **SOIL & WATER – 4**. With implementation of the permit requirements, staff does not believe there would be significant impacts to soil resources during operation of BSEP.

Staff reviewed the applicant's conceptual BMPs for controlling storm water drainage to assure that appropriate erosion control and drainage measures are identified to avoid degradation of water quality from water encountering soil or chemicals deleterious to aquatic and terrestrial plant and wildlife. Potentially significant water quality impacts could occur during operations if contaminated or hazardous materials used during operations were to contact storm water runoff and drain off-site. If natural storm water drainages were altered, potentially significant impacts could occur in areas not protected with permanent BMPs through concentrated drainage and ensuing soil erosion and sediment transportation off-site. Recognizing these potential impacts, the applicant has prepared a draft SWPPP that would be required by the general NPDES permit for industrial activity. Condition of Certification **SOIL & WATER – 4** requires the project owner to obtain Compliance Project Manager (CPM) approval and implement the final industrial SWPPP and monitoring plan and comply with the conditions of the general NPDES permit Order 97-03-DWQ for discharges of storm water associated with industrial activity. SWPPP procedures also include submitting a Notice of Intent (NOI) to the State Water Resources Control Board (SWRCB).

*Temporary and permanent disturbances associated with construction and operation of the proposed project would cause accelerated wind- and water-induced erosion. However, staff has concluded that the implementation of proposed mitigation measures, the construction and operation SWPPPs, and Condition of Certification **SOIL & WATER-5** that the project would not contribute significantly to cumulative erosion and sedimentation impacts. Staff recommends that BSEP develop a site specific DESCP that addresses all project storm water elements as part of this condition of certification to ensure protection of water quality and soil resources during construction and operation of the project. This condition of certification requires Kern County to conduct a review of the proposed project and provide its written evaluation as to whether the proposed grading, drainage improvements, diversion channel design, and flood management activities comply with all county requirements. The project owner would also be required to obtain CPM approval of the DESCP.*

Storm Water

Construction Storm Water

The BSEP site would be located primarily in an abandoned agricultural field. Sparse scrub and brush would be cleared prior to grading. Potentially significant water quality impacts could occur during construction, excavation, and grading activities if contaminated or hazardous soil or other materials used during construction were to contact storm water runoff and drain off-site. Water quality could also be impacted if the storm water drainage pattern concentrates runoff in areas that are not properly protected with BMPs causing erosion of soils and sediment discharge off-site and possibly into surface waters.

Development typically increases site runoff because of increased impervious areas or other changes to the site’s soil infiltration capacity. Drainage system improvements reduce the time of concentration of the flow and increases peak storm water runoff rates. Staff reviewed the BSEP Conceptual Drainage Study which evaluated storm water runoff for pre-developed conditions onsite and offsite and post-development (operations) conditions at the site.

Potentially significant soil erosion impacts would occur in areas not protected with BMPs for construction. Recognizing these potential impacts, the applicant has prepared a draft construction SWPPP which is required by the general NPDES permit 99-08-DWQ for construction activity.

Condition of Certification **SOIL & WATER–4** would require the applicant to comply with the requirements of the general NPDES permit for discharges of storm water associated with construction activity. With implementation of the permit requirements and Condition of Certification **SOIL & WATER-5**, staff does not believe there would be significant impacts due to storm water runoff on and offsite during construction.

Several project features would contribute to potentially significant water erosion, including the large volume of earth displaced, the long duration of construction, and soil properties that have a low to moderate potential for water erosion.

Construction of the BSEP would add impervious areas to the site, causing an increase in storm water runoff. Drainage and erosion control measures that create a separate drainage system for the power plant are proposed and, during grading work, soil would be stabilized by maintaining sufficient water content to make it resistant to weathering and wind erosion. However, a draft SWPPP has been prepared that provides conceptual plans for erosion and drainage control measures that would be used during project construction (BS 2008a). The draft SWPPP includes BMPs for properly storing and containing hazardous materials used, and hazardous waste generated, during the course of construction. Staff concludes that through the proper application of BMPs in accordance with these conditions, the impact to water quality and soil and water resources from storm water drainage should be reduced to less than significant levels. Staff also concludes that through implementation of onsite detention/ infiltration areas that the site improvements would not increase runoff from the site and raise peak flood levels downstream.

Operations Storm Water

Staff reviewed the applicant's hydrologic calculations in the Conceptual Drainage Study to evaluate the offsite areas tributary to the BSEP site and the proposed drainage plan for onsite storm water runoff. Storm water from offsite areas historically reaches and flows across the site via Pine Tree Creek and small drainage swales. As proposed, the BSEP project would alter historic storm water flow paths and change typical runoff patterns from the property. A detailed discussion of Staff's storm water review and watershed-scale assessment of storm water emanating from the Pine Tree Creek watershed is presented in **SOIL and WATER Appendix C** and summarized below.

Site development would result in the formation of ten individual, gently northward sloping, planar "cells". Ten onsite drainage ditches are designed to be constructed at the downslope (northern) edge of each cell to collect rainfall runoff and nuisance water runoff originating from site maintenance activities. The ditches are designed to flow from west to east, carrying runoff from each "cell". The ditches were sized using the Manning's Equation and Bently Flowmaster computer program for high intensity short duration rainfall. Flow velocities were designed to typically be 3 to 4 fps. Flow depths within the ditches are designed to be less than one foot deep. No freeboard is provided in the design for these shallow ditches. Seven of the ditches (southernmost) are currently designed to drain directly to the proposed diversion channel. The three northernmost ditches drain to a retention basin located near at the northeast corner of the proposed site development.

Staff has reviewed the engineering design methods used by the BSEP to design a retention basin for maintaining pre-development peak flows from the site. The use of one onsite retention basin does not address LRWQCB and CDFG comments and Kern County requirements regarding undetained discharge from industrial areas. Based on these comments and staff's review, staff has determined that runoff from the site as well as potential nuisance flows or discharges of hazardous substances from plant operation and maintenance would cause significant impacts to the receiving waters. Staff is also concerned that the proposed retention basin design, located within the solar field, would make maintenance and sediment removal difficult. Staff concludes that a retention basin with a design depth of only 5 inches would be difficult to monitor and determine when sediment should be removed. Staff also concludes that a rock lined weir is not a sufficient hydraulic control for the retention basin outlet structure that is sized based on only inches of hydraulic head. Staff has determined the proposed retention basin is also located in an area where the soils have low percolation rates.

Staff has concluded that the terrain, originating from the Chuckwalla Mountains, slopes toward the BSEP site and may have historically drained to the site. An offsite drainage ditch currently diverts the offsite tributary area away from the site to the north. Staff requests that BSEP provide an adequate routing assessment of the ditch to assess its capacity and flow path and assure the adjacent property owners are not impacted by BSEP diverting storm water away from the BSEP property. Staff is also requesting that BSEP include a maintenance discussion for this ditch as needed to route peak flood flows from the site and avoid future potential flood related impacts.

Staff believes that the current onsite storm water management plan does not adequately protect the site and downstream areas from potentially significant storm water impacts. To assess potential impacts caused by the proposed drainage features, staff requests that the applicant revise the Conceptual Drainage Study to address the following concerns:

1. Staff requests that the applicant revise the onsite hydrology calculations using methods acceptable to Kern County to account for the increased impervious areas of the solar field site.

2. Staff requests that the applicant include hydrologic calculations for all areas offsite that historically drain to the property. Where diversions (manmade or natural) or a split flow condition exists upstream of the site, provide calculations describing the adequacy of the diversion to control the 100-year peak flow. At a minimum, qualitatively describe the diverted flow path to the Jawbone Creek. Where applicable provide evidence that all offsite storm water diversion facilities would be maintained and that no adjacent properties are impacted as a result of the diversion away from the site.

3. The revised hydrologic analysis should consider changes to the infiltration capacity of the onsite soils following site development. Soil infiltration characteristics may be permanently impacted by site development. The application of soil treatments to control soil loss may also cause more frequent runoff from less intense storms that may have historically infiltrated without producing any runoff.

4. Staff has concluded that the drainage ditches would need to be enlarged to account for final revisions to the post-developed hydrology. Staff recommends that each conveyance provide adequate freeboard to reduce the risk of overflows.

5. Staff also recommends that these conveyance elements drain to a retention basin as opposed to discharging directly into the proposed diversion channel.

6. Staff recommends that the BSEP design retention basins to collect runoff from the entire solar field site to avoid potential impacts to receiving waters. This can be achieved with multiple retention facilities. Retention basin analyses should be based on guidance from the Kern County Hydrology Manual. The retained storm water runoff must infiltrate and/or evaporate within seven days to comply with Kern County requirements.

7. Staff recommends that the BSEP develop a contingency plan for potential discharges of hazardous substances from the industrial site that would contact storm water and follow designated drainage paths to the receiving waters.

Based on staff's hydrologic analyses (see **SOIL and WATER - Appendix C**), staff believes that the use of 20,000 cfs for the Pine Tree Creek peak design flow is reasonable. As part of the requirements of Condition of Certification **SOIL & WATER-6**, the project owner would be required to show evidence that Kern County and FEMA have accepted the design flow for the diversion channel. Hydrologic calculations for the Pine Tree Creek watershed and smaller offsite tributaries would be required for agency approval. The CLOMR condition of certification would also require BSEP to develop peak flood flow estimates for the 10-, 2-, 1-, and 0.2-percent annual chance flood events based using hydrologic modeling methods acceptable to FEMA.

Staff recommends that the applicant develop a channel stabilization plan for the design flow based on the establishment of a homogeneous and stable channel slope which would reduce velocities and thus erosion potential. With the channel profile controlled, existing bank erosion can be mitigated and future impacts due to development minimized. The selective bank treatments recommended by staff in **Soil and Water-Appendix C** would minimize environmental impacts, mitigate unavoidable impacts, and preserve the natural character of the excavated channel. These recommendations are provided in accordance with the provisions of the CDFG's response to BSEP's Streambed Alteration Agreement (CDFG, 2009).

Geomorphic Assessment

Staff's geomorphic assessment presented in **Soil and Water- Appendix C** has predicted the diversion channel would become braided and down-cut in areas too steep to maintain a stable channel. BSEP has not presented mitigation strategies to reduce these potentially damaging geomorphic conditions. For example, grade stabilization would minimize streambed lowering, would reduce average velocities and shear stresses, and would improve hydraulic stability; the potential for bank erosion and undercutting can also be reduced. Staff anticipates that the hydraulic response of the diversion channel, as proposed, may result in long term morphological changes as the channel tries to reach an equilibrium slope condition that is flatter than proposed.

Staff requests a geomorphic study be conducted by a fluvial geomorphologist with expertise in arid system channel design. The geomorphic study should address the following key issues:

1) Discuss the stability of existing Pine Tree Creek wash, as it pertains to active alluvial fan morphology, debris flows, erosion, sediment movement and deposition, and channel migration.

2) Selection of an appropriate reference reach (similar watershed characteristics, hydrology, and sediment) to help predict the channel's geomorphic response.

3) Sediment transport analysis that includes the following:

    a. Grain size distributions from Pine Tree Canyon sediment samples and samples taken within the channel on the alluvial fan.

    b. A discussion of Pine Tree Creek watershed as a potential source of sediment, the active erosional and depositional conditions of the wash, the sediment transport capacity of the existing wash and proposed diversion channel, and the proposed sediment load and flux anticipated with the proposed channel.

    c. Recommendation for applying bulking factors to the base flood flow.

    d. Provide a discussion of anticipated maintenance requirements and measures that would improve opportunities for successful mitigation.

4) Low flow channel design for the ultimate diversion channel.

The revised channel design would need to be re-assessed before a determination can be made about the anticipated geomorphic response of the channel. Staff recommends that the applicant assess the geomorphic response along the entire channel reach and design appropriate bank and toe protection that would sufficiently address the lateral migration of the channel, head-cutting in the channel, and local scour anticipated at design flow conditions. While down-cutting may reduce the potential for the channel to meander into the bank, it is not a sustainable condition for maintaining the geomorphic function of the channel.

Historic Floods

Staff conducted research on historic flood events near the BSEP to recognize the potential flood hazards associated with desert hydrology (See **Soil and Water - Appendix C**). Two large rainfall events were measured in 1961 and 1997 in the Pine Tree Canyon. These historic rainfall-runoff events are shown in **Soil & Water** - **Figure C1** to signify that rainfall events can occur well above predicted peak flow used for design. In fact, the Red Rock Canyon storm plotted well above the 100-year peak flow regression analysis yet was identified as only a 50-year event. Staff recognizes that stream gauge estimates are based on both runoff and sediment in the flow. Sediment can increase clear water flow estimates by as much as 200% (See **Soil and Water - Appendix C**). In desert streams, it is also common for the peak flows to decrease in a downstream direction, especially after leaving the mountains (USGS, 1997a) where flows may flood the plains, infiltrate and attenuate the peak flow.

Flooding

The existing Pine Tree Creek flood hazard is identified in the effective Digital Flood Insurance Rate Map for Kern County. The special flood hazard area is mapped "Zone A" which is a result of approximate methods used to delineate an area with a high potential for flooding (FEMA 2008). Immediately downstream of the site, Pine Tree

Creek joins Jawbone Creek. Jawbone Creek is mapped Zone AE with Base Flood Elevations (BFE) determined. The applicant's proposed plan to divert Pine Tree Creek entails a point of diversion, a new alignment, and a connection back to the Pine Tree Creek near the confluence with Jawbone Creek. The proposed diversion channel would result in a change to the FEMA SFHA.

Staff has concluded that BSEP did not provide a detailed assessment of the existing Pine Tree Creek flood hazards. Without knowledge of the existing condition flood hazard, staff was unable to assess the potential impacts caused by the proposed project. Staff requests that the BSEP conduct a detailed engineering analyses to determine the existing Pine Tree Creek flood hazards upstream, onsite, and downstream of the property. Staff recommends that existing conditions analyses tie into Jawbone Creek immediately downstream of BSEP.

Changes to the FEMA SFHA would require a Conditional Letter of Map Revision (CLOMR) to address LORS and comply with the Kern County Floodplain Management Ordinance. The existing conditions analyses would be required as part of the FEMA CLOMR process. Because the site is mapped with a Zone A SFHA, BSEP would be required to follow Zone A map revision requirements described in Managing Floodplain Development in Approximate Zone A Areas, A Guide for Obtaining and Developing Base (100-Year) Flood Elevations (FEMA, 1995). The primary requirement would be to tie in at the approximate floodplain limits of the effective flood hazard.

One Percent Risk Flow

According to Kern County's Division Four Standards for Drainage, the One Percent Risk Flow is the flow on the alluvial fan based upon the joint probability of the flow distribution at the fan apex and the probability of occurring at the development site (Kern County Division 4 standards). Based on staff's geomorphic assessment (**Soil and Water - Appendix C**) it appears that the channel immediately upstream of the point of diversion, the property line, does not have the capacity to deliver 20,000 cfs to the BSEP site without flowing out of bank (see Soil & Water Figure C2).

Existing Pine Tree Creek Flood Hazards

Based on staff's analyses of the One Percent Risk Flow, it is estimated that roughly 4,000 cfs would be contained in the channel at the location of the proposed diversion (Turn #1). Peak flow discharge greater than the channel capacity (4,000 cfs) would sheet flow overland toward the northeast. The exact flow path was approximated by staff. Staff found that the out of bank discharge would sheet flow across the property to the south and to the east of BSEP. This flood path is not recognized on the effective SFHA delineation for Pine Tree Creek. To fully understand the existing flood hazards, staff requests the applicant conduct an existing conditions flood hazard assessment to determine the approximate flood limits upstream of Jawbone Creek.

The upstream limit of the effective Jawbone Creek detailed study was at Munsey Road just north of the BSEP. Staff was made aware that the Honda Proving Center was constructed within the Jawbone Creek SFHA in the late 1980s or early 1990s and that the owner did not apply for a letter of map revision for the site (Aaron Leicht, pers comm., January 6, 2009). The Honda Proving Center or any other undocumented encroachment into the FEMA floodplain for Jawbone Creek would result in the existing 100-year floodplain being different than the effective SFHA shown on DFIRM.

Open Channel Hydraulics study of the Diversion Channel

Pine Tree Creek, a dry desert wash, trends south-southwest to north-northeast through the center of the property. The entire Pine Tree Creek wash across the site, about 8,150 feet long, would be filled and developed into the solar facility. The applicant is proposing to intercept and route Pine Tree Creek around the periphery of the solar facility in an earthen, trapezoidal-shaped channel (diversion channel). The diversion channel is proposed entirely within the site property boundary.

Staff reviewed the applicant's design for the proposed diversion channel and has determined that the flow velocities in the channel are high relative to the expected stability of the earthen channel(**Soil and Water - Appendix C**). High velocities and deep concentrated flow tend to increase shear stresses on the channel, which result in a greater potential for failure. Staff did not have access to an investigation by a soil engineer who can validate the channel's strength.

Staff has reviewed the applicant's hydraulic calculations. It appears that no specific design criteria (velocity, shear stress, Froude, depth, etc) was developed for the design flow to ensure that the banks and bed of the channel resist the hydraulic forces of the design flow. It also appears that the proposed water surface profile for the design flow of 20,000 cfs would be contained within levied reaches of the channel.

Point of diversion

At the upstream end of the diversion, where the proposed constructed-channel intercepts the natural channel of Pine Tree Creek, a 5.0 foot high berm is proposed. Staff has considered this berm to be a levee and acknowledges that its design would be required to meet the requirements of Chapter XI of the County's Division Four Standards for Drainage. Staff is also concerned about the transition from the natural channel to the proposed channel. At the property line, the floodplain width of the natural channel is much wider than the proposed diversion channel. This configuration would result in a substantial contraction to the flow. Sediment-laden flow might also create problems with sedimentation and maintenance at this location.

BSEP Hydraulic Analysis

To evaluate the flood potential of the proposed diversion channel, staff reviewed BSEP's hydraulic methods and calculations used as the basis for the channel design. Staff reviewed the applicant's hydraulic assumptions such as roughness and boundary conditions, bank and toe treatments, low flow channel design and transitions to and from the natural channel. Staff's comments are provided in Soil and Water Appendix C.

Based on the location and alignment of the proposed diversion channel outfall, staff concludes that the proposed flood hazard boundary would not tie into the existing SFHA shown on the effective DFIRM immediately downstream of the site. Staff recommends that BSEP extend the hydraulic analysis downstream to Jawbone Creek. This effort would result in a continuous detailed study from the mouth of Pine Tree Creek to a sufficient distance upstream of the site and allow for an adequate assessment of the proposed project. Staff concludes that the applicant has not sufficiently addressed the downstream mapping restrictions and recommends that BSEP identify the most appropriate outfall to Jawbone Creek that would minimize impacts to adjacent property owners.

Staff's Hydraulic Model

To analyze the applicant's hydraulic analysis of the proposed diversion channel, staff developed a backwater hydraulic model using the Army Corps of Engineers HEC-RAS computer model. Staff setup the hydraulic model using channel dimensions and assumptions from the applicant's design. Results of the HEC-RAS model are discussed in Appendix C. The Appendix also presents an alternative analysis to examine a modified channel design.

The results of staff's analyses has concluded that the channel as designed is too steep to convey the design flood flow of 20,000 cfs. Results from staff's hydraulic modeling of the proposed channel show high velocities (greater than 7 fps), high shear stress, Froude numbers greater than 0.8, and depths greater than 5.0 feet. To mitigate these impacts staff recommends that the applicant re-evaluate the design of the channel to bring hydraulic conditions within typical thresholds for earthen channels. There are also specific design changes that are required before the proposed channel would meet Kern County's Division Four criteria.

Staff found the channel banks are designed to slope at 3 foot horizontal to 1 foot vertical (3:1). This design does not meet the requirements of Kern County Division Four Standards for Drainage, which require a minimum of 4:1. Staff is requesting that BSEP revise the channel design to comply with the Kern County design standards. Staff further requests that the applicant provide a hydraulic analysis for the existing conditions and the revised diversion channel using numerical models approved by FEMA. The hydraulic analysis is requested so that staff can adequately review the existing flood hazards at the site, the potential flood impacts as a result of the proposed project, and the adequacy of the mitigation to meet the Kern County Floodplain Management Ordinance.

Staff has concluded that the channel as proposed would not carry the 20,000 cfs design flood without the need to contain the flood within levied reaches of the channel. Kern County specifies the design criteria for levees to be in accordance with the latest revision of the US Army Corps of Engineers Design and Construction of Levees, Engineer Manual EM1110-2-1913. The USACE guidance is also required per FEMA guidance contained in 44 CFR 65.10. Staff has concluded that the BSEP diversion channel would meet these levee standards and requirements and the engineered levee would mitigate potentially significant flood related impacts once the project owner has complied with Condition of Certification **SOIL & WATER-6** which requires the applicant to obtain a CLOMR prior to channel construction. The conditions of the CLOMR would ensure that levied reaches of the channel are constructed to the USACE's engineering design standard for the base flood and would adequately reduce the risk of flooding on areas adjacent to the diversion channel, including the BSEP site.

The key findings and outstanding issues identified by our assessment are summarized below.

1) The existing conditions flood hazards have not been determined.

2) The resulting channel velocities are too high.

3) The hydraulic depth of flow is too deep.

4) The resultant Shear Stress is too high for proposed bank treatments.

5) The Froude Number should be lowered to a more stable channel flow regime.

The proposed channel, as designed, does not adequately address the adverse hydraulic conditions that would result from the design discharge or, for that matter, the bankfull discharge. Staff requests that the applicant revise the diversion channel design to address the following concerns:

1) Delineate the approximate flood hazard area upstream of the site using numerical modeling tools to determine the existing conditions

2) Re-assess the channel design at the point of diversion. Provide detailed hydraulic calculations describing the transition from natural channel to the diversion channel. Staff requests that the applicant respond to the following questions:

   a. Based on the existing flood hazards (not what is mapped), is the point of diversion designed to capture and divert the design flood of 20,000 cfs?

   b. Is the turning radius sufficient to meet Kern County design standards?

   c. Is the berm designed to meet the FEMA's regulatory requirements?

   d. Is the point of diversion revetment design adequate for preventing head-cutting erosion and adequate for the transition to the diversion channel? (see CDFG comments from February 19, 2009)

   e. Can the diversion channel be constructed entirely onsite without causing flood or erosion impacts to neighboring properties?

3) Establish design criteria to adequately pass the design flood flow without increasing the potential for out of bank flooding.

4) Comply with CDFG technical comments and provisions of the Streambed Alteration Notification 2008-0146-R4.

5) Assess and recommend a geomorphically stable low flow channel.

6) Rely on low impact mechanisms for channel and bank stability (when applicable),

7) Require minimal maintenance and promote sustainability for native vegetation

8) Provide habitat for species of concern and maintain the biological function and values of Pine Tree Creek

9) Determine the soil characteristics and its ability to resist shear before establishing the design criteria.

Staff also requests that the applicant consult with a soils engineer and provide a Soils Engineering Report for Staff's review. The soil engineering report shall include data regarding the nature, distribution, and strength of existing soils, conclusions and recommendations for grading procedures. The Soils Engineering Report is requested to address three related Soil and Water issues:

1) Alluvial Fan Construction Constraints: This discussion may be provided as part of the Sediment Transport analyses

2) Site Drainage:

    a. The Report shall discuss the potential changes to the soil infiltration characteristics following construction activities and under application of erosion and dust control measures that may reduce infiltration rates.

    b. Soil borings shall be taken at each retention basin location and field tests taken to identify percolation rates near the proposed pond bottom elevation.

3) Design criteria for the Pine Tree Creek diversion channel:

    a. A soils investigation would provide boring logs of the soils in the existing Pine Tree Creek wash upstream and downstream of the existing fault.

    b. Soil borings shall also be required along the centerline of the proposed diversion channel, spaced appropriate for a geotechnical engineer to provide slope, scour, and elevation stability analysis for the proposed channel.

    c. The Soils Engineering Report should also include a discussion of the similarities between the soil characteristics of the future diversion channel bed and the existing channel bed.

    d. The report shall discuss the stability of the diversion channel slopes under hydrostatic and hydraulic loading and provide recommendations for corrective measures.

Staff requests that the Soils Engineering Report be submitted to Kern County for review per the requirements of the County Building Regulations under Chapter 17. Staff requests a copy of the final report with County comments addressed prior to completion of the FSA.

SFHA Revisions / CLOMR Requirements

Once the existing flood hazards have been studied and the revised channel design has been reviewed by staff and meets the Kern County Floodplain Management Ordinance, staff recommends that the project owner coordinate with Kern County to submit a request for a CLOMR to FEMA. FEMA would review and comment on the proposed change to the Pine Tree Creek SFHA. Staff recommends Condition of Certification **SOIL&WATER- 6** to ensure that the proposed revision to the FEMA regulated floodplain meets the minimum floodplain management criteria of Kern County and the NFIP. In order to address LORS staff recommends BSEP be required to comply with the conditions in the CLOMR. This condition of certification would ensure the applicant has received an approved FEMA CLOMR for the project prior to site mobilization and is following the guidance from FEMA to avoid potentially significant impacts caused by floods.

As currently presented, it appears that the re-aligned Pine Tree Creek may impact adjacent property owners, which does not meet Kern County standards, and would result in a significant impact. The applicant must demonstrate that the proposed Pine Tree Creek re-alignment would not increase flooding to neighboring properties. To ensure the County's standards are met, staff is recommending, as part of Condition of Certification **SOIL & WATER- 6,** that BSEP follow design guidelines described in Kern County Division Four, Standards for Drainage and notify adjacent property owners who are shown to be affected by the proposed change to the existing SFHA. To avoid significant flood impacts to adjacent properties, BSEP would be required to submit copies of these notices and acknowledgment letters from the property owners as part of the FEMA CLOMR process.

As part of the CLOMR application, BSEP must identify a public entity which would be responsible for channel maintenance. Operation and maintenance plans of the proposed of flood control measures on areas subject to alluvial fan flooding are specified under 44 CFR 65.10 (c) and (d). Currently the County of Kern does not have a Flood Control District in place, which could serve as the maintenance entity. BSEP would therefore be required to either form a District as part of the project or find an entity outside the County that would be willing to accept maintenance responsibilities (Kern County 2008). Staff recommends **SOIL&WATER-7** which would require the Project Owner to develop a Maintenance District, in perpetuity, to manage the diversion channel maintenance and avoid significant flooding or soil erosion related impacts from diverting Pine Tree Creek wash.

It is assumed that the project owner would develop a flood management plan to remove the BSEP plant from areas with the proposed SFHA defined with BFEs. Given the uncertainty of defining the flood hazard on alluvial fans, it is possible that portions of the site might be mapped in areas prone to shallow flooding. If the proposed development site remains in a flood-prone area (Zone AO or Zone X shallow flooding), all new construction must (i) be designed (or modified) and adequately anchored to prevent floatation, collapse, or lateral movement, (ii) be constructed with materials resistant to flood damage, (iii) be constructed by methods and practices that minimize flood damages, and (iv) be constructed with electrical, heating, ventilation, plumbing, and other service facilities that are designed and/or located so as to prevent water from entering or accumulating within the components during conditions of flooding [44 CFR 60.3(a)(3)].

Letter of Map Revision (LOMR)

As soon as practicable, but not later than six months after the end of construction, the project owner, through a request from Kern County, must notify FEMA of the changes by submitting technical or scientific data as part of a Letter of Map Revision (LOMR) request, in accordance with 44 CFR 65.3. A LOMR is required after physical changes to the floodplain have changed the flood hazard information shown on the effective DFIRM. The request must be accompanied by the appropriate portions of the MT-2 application forms package, titled Revisions to National Flood Insurance Program Maps (FEMA Form 81-89 Series), applicable fees, and the required supporting information. Staff has recommended Condition of Certification **SOIL & WATER-6** to ensure the project owner complies with the conditions in the CLOMR and reports to FEMA that the project has been completed as stated in the CLOMR. Significant variations to the design require prior approval from FEMA. This condition would be met once the CPM has accepted the approved FEMA LOMR. The LOMR would provide evidence that BSEP has adequately identified flood hazards associated with the project and has mitigated adverse flood impacts to adjacent properties.

CUMULATIVE IMPACTS AND MITIGATION

Cumulative impacts represent impacts that are created because of construction and operation of the proposed project in combination with impacts from other past, present, or reasonably foreseeable future projects. Cumulative impacts can result from individually minor, but collectively significant, actions taking place over time in the same area.

Construction and operation of the proposed project would result in both temporary and permanent changes at the project site. These changes could incrementally increase local soil erosion and storm water runoff. Potential project related soil or storm water cumulative impacts could be reduced to a level of insignificance through implementation of the applicant’s proposed mitigation measures/BMPs and project DESCP; implementation of the SWPPPs for the Construction and Industrial Activities; NPDES permits; and compliance with all applicable erosion and storm water management LORS.

The applicant proposes to use high quality fresh groundwater for construction and operation of the BSEP. Daily water demand during construction would initially be significant during the first five months of site preparation and rough gradingStaff estimates that the initial construction water use could exceed 6,752 AF. Following the five-month long initial grading period, water use is expected to decrease to a rate of approximately 400,000 gpd for a period of 21 months or 462 days. According to the AFC, this decreased construction water use could consume as much as approximately 185 million gallons or 567 AF. Combined, the volume of water used for construction of the BSEP could approach 7,319 AF over a 26-month period.
The annual potable water use by the project is expected to be approximately 8 AFY, and project operations are anticipated to consume about 1,600 AFY of groundwater. Staff estimates that construction and operation of the project would consume more than 60,000 acre feet of potable water, equating to more than 20 billion gallons of potable water, during the 30-year life of the project.

Increased groundwater consumption by existing users or future new users would decrease the storage recovery rate and could begin to remove groundwater from storage. Long-term groundwater storage declines would negatively impact water users by increasing pumping lifts, possibly causing wells to go dry, and negatively impacting the primary portable water supply to the Fremont Valley. This is significant because the AFC notes the population and quantify of groundwater consumed in the adjacent California City sub-basin is projected to increase over the next decade. The California City sub-basin is in partial hydraulic connection with the Koehn sub-basin. Also, water level declines below historical lows could increase the risk for land subsidence. Water quality could degrade over time if hydraulic gradients, which presently are towards Koehn Lake, reverse causing highly saline groundwater beneath the lake bed to migrate southwest toward potential pumping depressions.
Cumulative impacts to high quality fresh groundwater resources from the BSEP can be avoided by using a degraded water source such as that available in the vicinity of Koehn Lake (see **Soil and Water Appendix D** and **ALTERNATIVES** section of this document)

COMPLIANCE WITH LORS

Staff has reviewed the LORS and policies presented in **Soil & Water Table 1** and believes the project, as proposed, does not comply with all LORS. A discussion of selected LORS is presented below.

CODE OF FEDERAL REGULATIONS TITLE 44

Staff has determined that the Beacon Solar project would be required to comply with local flood management ordinances and submit an application to FEMA for a Letter of Map Revision (LOMR). Rules regarding data requirements and procedures for obtaining LOMRs are outlined in Title 44, Chapter I, Part 65, Code of Federal Regulations. Staff is requiring Conditions of Certification ***SOIL & WATER-6*** *to ensure Beacon Solar would comply with the local and federal requirements.*

SWRCB RESOLUTION 75-58 AND ENERGY COMMISSION'S 2003 INTEGRATED ENERGY POLICY REPORT

Staff has determined that, as proposed, the BSEP does not comply with SWRCB Resolution 75-58 and Energy Commission's 2003 Integrated Energy Policy. These *water policies applicable to this project stem from, among other things, Article X, section 2 of the California Constitution, which declares that "*the general welfare requires that the water resources of the State be put to beneficial use to the fullest extent of which they are capable, and that the waste or unreasonable use or unreasonable method of use of water be prevented…" *In order to better define what "unreasonable use" means in terms of power plant cooling, the SWRCB issued Resolution 75-58, "Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling" (Resolution 75-58). It sets forth, in priority order, a list of preferable water sources for power plant cooling as follows: (1) wastewater being discharged to the ocean, (2) ocean, (3) brackish water from natural sources or irrigation return flow, (4) inland wastewaters of low TDS, and (5) other inland waters.*

*The resolution also states that fresh inland waters should only be used for power plant cooling if other sources of water or other methods of cooling would be environmentally undesirable or economically unsound. Since adopting Resolution 75-58 in 1976, the SWRCB has more recently confirmed the ongoing applicability of its policy for cooling of modern power plants and clarified a basic principle by stating, "*The policy requires that the lowest quality cooling water reasonably available from both a technical and economic standpoint should be utilized as the source water for any evaporative cooling process utilized at these facilities*" (SWRCB 2002a).*

*Based, in part, on the State Constitution and SWRCB Policy 75-58, the Energy Commission adopted its own policy for water conservation in the cooling of power plants. The Energy Commission's 2003 IEPR specifies that "*the Energy Commission would approve the use of fresh water for cooling purposes by power plants which it licenses only where alternative water supply sources and alternative cooling technologies are shown to be 'environmentally undesirable' or 'economically unsound'*".*

The applicant proposes the use of high quality fresh groundwater for power plant construction (primarily dust suppression and grading) and operation (primarily power plant cooling). Use of high quality fresh groundwater for power plant cooling is in direct conflict with Energy Commission and SWRCB policies concerning water use.

Due to the direct conflict of the proposed water use with Energy Commission and State Water Board policies, staff conducted an independent economic feasibility study to evaluate the viability of using other water sources, cooling technologies and project alternatives. Evaluations of these analyses are included in **Soil and Water Appendix D** and the **ALTERNATIVES** section of this document. The alternatives analysis started rather broadly but was quickly focused to 3 viable alternatives; 1) the use of brackish water obtained from the vicinity of Koehn Lake, 2) dry cooling and 3) complete project redesign to use Photo Voltaic technology.

The use of brackish water would require treatment beyond that proposed by BSEP for power plant operation. Due to the additional treatment of the alternative water supply, waste in addition to that identified by BSEP would be generated. Dry cooling would eliminate the need for additional water treatment. In addition, waste generation and waste disposal would be minimized using dry cooling technology.

While conducting the economic feasibility study, staff compared the estimated costs of the alternatives with the estimated costs of the project as proposed. This analysis is presented in **Soil and Water Appendix D** and in the **Alternatives** section of this document.

The economic feasibility study determined that both, the use of degraded groundwater and dry cooling, are viable reasonable alternatives to the project as proposed and are not "economically unsound". Staff has also shown that the use of a dry cooling alternative may actually result in lower project operating costs. Staff believes that since there are economically sound alternatives to freshwater use, the use of freshwater for power plant cooling is not consistent with Energy Commission Policy.

Staff believes the applicant should select a project alternative from the list provided in the **ALTERNATIVES** section of this document and propose a design alternative that eliminates fresh water use for evaporative cooling.

With respect to wastewater, the Energy Commission's 2003 IEPR specifies that "the Energy Commission will require zero liquid discharge technologies (ZLD) unless such technologies are shown to be 'environmentally undesirable' or 'economically unsound.'" As discussed above under process wastewater impacts the applicant proposes to dispose of process wastewater in lined evaporation ponds. The LRWQCB has determined that the information provided by the applicant is insufficient to analyze the proposed waste discharge to land and has significant questions the applicant must address. This information is also needed for staff to complete an analysis of environmental impacts. Also, in the **Biological Resources** section of this document, it is expressed by staff, CDFG and USFW that large evaporation ponds may result in potential impacts to wildlife.

Given these concerns and current deficiencies in the design of the proposed waste discharge to land, staff believes the applicant has not adequately demonstrated the use of ZLD is an 'environmentally undesirable' or 'economically unsound' wastewater treatment and disposal alternative. While staff believes the applicant should further evaluate alternative water supplies and/or cooling technologies staff recognizes depending on the water source or cooling alternative chosen there could be a significant effect on the volume of wastewater that would be generated. This change in volume could also change the economic feasibility and environmental desirability of a wastewater disposal alternative. Therefore, staff believes the applicant should further evaluate wastewater disposal as a part of the analysis for alternatives to the use of freshwater.

CONCLUSIONS

As proposed, the project will cause significant environmental impacts, does not comply with existing water policies, and, in some cases, does not comply with LORS. A summary of staff conclusions is presented below.

- The proposed use of high quality fresh groundwater for power plant cooling is in conflict with State Water Resources Control Board and Energy Commission policies.
- There is no compelling evidence that using the lowest quality water supply reasonably available (brackish water near Koehn Lake) would be environmentally undesirable or economically unsound.
- There is no compelling evidence that alternative cooling technologies would be environmentally undesirable or economically unsound.
- Staff's analysis shows other alternatives to wet cooling are economically feasible.
- Staff believes the applicant should further evaluate alternative water supplies and/or cooling technologies and propose a design alternative that eliminates fresh water use for evaporative cooling.

- Historic groundwater pumping in the Fremont Valley Basin has resulted in groundwater overdraft and subsidence.
- Historic groundwater pumping in the Fremont Valley Basin has changed hydraulic gradients which could cause saline groundwater beneath Koehn Lake to flow towards freshwater portions of the basin.
- Groundwater level trends in the Fremont Valley Basin indicate current water levels remain substantially lower than historic high water levels and in some areas a continued decline.
- The balance between water inflows and outflows in Freemont Valley groundwater sub-basins, and the Basin on a whole, is sensitive to changes in groundwater pumping rates and use.
- Groundwater levels in the Koehn Groundwater Sub-basin, which underlies the project site, have been slowly increasing or remain nearly steady; water levels in at least one well have been declining.
- The proposed use of onsite groundwater from the Koehn Sub-basin can more than double current consumption, affecting the water levels and storage volumes of a potable water supply.
- The groundwater model does not accurately portray existing groundwater conditions.
- The model calibration was updated in December 2008, but a number of previously reported simulations were not updated to reflect changes in modeled-aquifer parameters. Therefore, a lack of consistency exists between simulated impact and sensitivity test model runs.
- Project groundwater pumping could result in well interference and impact nearby groundwater users.
- As proposed, the evaporation ponds for wastewater disposal are not sufficiently sized to contain the anticipated waste stream.
- The project site is bisected by a mapped Special Flood Hazard Area. As proposed, the diversion channel intending to reroute flood flows around the project site is not adequate for 100-year flood flows.
- The proposed design for filling and realigning Pine Tree Creek does not meet Kern County standards and may result in a significant impact to adjacent property owners.
- The proposed site drainage plan is designed to collect and discharge concentrated runoff directly into the rerouted channel without reducing sediment loads, or removing site-generated contaminants.
- The runoff detention basins are not adequately designed to capture design storm site runoff.
- There is no plan for collecting, treating and disposing storm water that has been in contact with the power block or other mechanical equipment.

- Staff recommends that the following engineering studies be provided for review so staff can complete an analysis of potential environmental impacts from the proposed reconfiguration of Pine Tree Creek:
  - Revised Conceptual Drainage Study
  - Geomorphic Study
  - Revised Diversion Channel Design
  - Soils Engineering Report
- Staff recommends that the applicant provide verification that a maintenance district is being developed in accordance with LORS and to address County maintenance concerns for Pine Tree Creek.

PROPOSED CONDITIONS OF CERTIFICATION

SOIL&WATER-1: The project owner will comply with the requirements of the Kern County Environmental Health Services Department, regarding sanitary waste disposal facilities such as septic systems and leach fields.

Verification: The project owner will submit all necessary information and the appropriate fee to the county of Kern to ensure that the project has complied with the county's sanitary waste disposal facilities requirements. A written assessment prepared by Kern County of the project's compliance with these requirements must be submitted to the CPM for review and approval prior to the start of operation.

SOIL&WATER-2: The project owner shall comply with the requirements of the general National Pollution Discharge Elimination System (NPDES) permit for discharge of storm water associated with construction activity. The project owner shall develop, obtain compliance project manager (CPM) approval of, and implement a Storm Water Pollution Prevention Plan (SWPPP) for the construction of the BSEP site, laydown area, gas pipeline installation and all other linear facilities.

Verification: At least 60 days prior to site mobilization, the project owner shall submit to the CPM and LRWQCB, a copy of the construction SWPPP for review and approval prior to site mobilization. The project owner shall retain a copy of the SWPPP on site. The project owner shall submit to the CPM copies of all correspondence between the project owner and the LRWQCB regarding the NPDES permit for the discharge of storm water associated with construction activity within 10 days of its receipt or submittal. Copies of correspondence shall include the notice of intent sent to the State Water Resources Control Board (SWRCB), and the board's confirmation letter indicating receipt and acceptance of the notice of intent.

SOIL&WATER-3: Prior to the initiation of any streambed *__or wetland__* activities for pipeline installation(s), *__including horizontal directional drilling and jack & bore techniques,__* the project owner shall provide a copy of the following permits to the CPM as appropriate:

5. Section 404 acceptance of Pre-construction Notification for Nationwide Permit(s) from the U.S. Army Corps of Engineers.

6. Section 401 Water Quality Certification or a Waiver of Waste Discharge Requirements from the LRWQCB or the State Water Resources Control Board.

Modifications of the construction techniques to be used or the location of the crossing as a result of permit conditions must be reviewed and approved by the CPM. The project owner will notify the appropriate agency of any modifications to the construction techniques or pipe alignment and implement the terms and conditions contained in the permit(s). The final design and construction of the pipeline shall anticipate channel erosion or scour caused by flood related channel incision. The project owner shall complete all necessary engineering plans, reports, and documents necessary for Kern County to conduct a review of the proposed pipeline and provide its written evaluation as to whether the proposed utility crossing, at the FEMA regulated Zone B Special Flood Hazard Area, will comply with all county requirements. The project owner shall ensure compliance with all county standards and requirements for grading and erosion control.

__**Verification:**__ The project owner shall do all of the following:

1. No later than 90 days prior to start of site mobilization, the project owner shall submit to the CPM and LRWQCB, verification from the Department of the Army, Los Angeles District Corps of Engineers that the BSEP linear pipeline construction is not subject to jurisdiction under Section 404 of the Clean Water Act or provide a copy of the Section 404 Permit.

2. No later than 90 days prior to start of site mobilization, the project owner shall submit a copy of utility crossing engineering design to Kern County for review and comment. A copy shall be submitted to the CPM and LRWQCB no later than 60 days prior to the start of site mobilization for review and approval. The CPM shall consider comments received from Kern County.

3. At least 30 days prior to the start of construction, the project owner shall provide the CPM and the LRWQCB verification that the Streambed Alteration Agreement includes activities associated with construction of the gas pipeline.

4. At anytime during the planning for construction Modifications of the construction techniques to be used or the location of the crossing as a result of permit conditions must be reviewed and approved by the CPM.

SOIL&WATER-4: The project owner shall comply with the requirements of the general NPDES permit for discharges of storm water associated with industrial activity. The project owner shall develop, obtain CPM approval of, and implement an industrial SWPPP for the operation of the project.

Verification: At least 60 days prior to commercial operation, the project owner shall submit to the CPM a copy of the industrial SWPPP for operation of the project for review and approval prior to commercial operation. The project owner shall retain a copy on site. The project owner shall submit copies to the CPM of all correspondence between the project owner and the LRWQCB regarding the general NPDES permit for discharge of storm water associated with industrial activity within 10 days of its receipt or submittal. Copies of correspondence shall include the Notice of Intent sent by the project owner to the SWRCB.

SOIL&WATER-5: Prior to site mobilization, the project owner shall obtain CPM approval for a site specific DESCP that ensures protection of water quality and soil resources of the project site and all linear facilities for both the construction and operation phases of the project. This plan shall address appropriate methods and actions, both temporary and permanent, for the protection of water quality and soil resources, demonstrate no increase in off-site flooding potential, and identify all monitoring and maintenance activities. The project owner shall complete all necessary engineering plans, reports, and documents necessary for Kern County to conduct a review of the proposed project and provide its written evaluation as to whether the proposed grading, drainage improvements, diversion channel design, and flood management activities comply with all county requirements. The project owner shall ensure compliance with all county standards and requirements for grading, erosion control, and flooding for the life of the project. The plan shall be consistent with the grading and drainage plan as required by Condition of Certification **CIVIL-1**. The DESCP shall contain the following elements:

- ***Vicinity Map*** – A map shall be provided indicating the location of all project elements with depictions of all significant geographic features to include watercourses, washes, irrigation and drainage canals, major utilities, and sensitive areas.
- ***Site Delineation*** – The site and all project elements shall be delineated showing boundary lines of all construction areas and the location of all existing and proposed structures, pipelines, roads, and drainage facilities. Adjacent property owners shall be identified on the plan maps. All maps shall be presented at a legible scale
- ***Drainage*** – The DESCP shall include the following elements suitable for submittal to FEMA as part of **SOIL & WATER-6**:
    a. Topography – Topography for offsite areas are required to define the existing upstream tributary areas to the site and

downstream to provide enough definition to map the existing Pine Tree Creek flood hazard. Spot elevations shall be required where relatively flat conditions exist.

b. Proposed Grade – Proposed grade contours shall be shown at a scale appropriate for delineation of onsite sub-basins, drainage ditches, pond contours, diversion channel, and tie-ins to the existing topography.

c. Hydrology - Existing and proposed hydrologic calculations for on-site areas and offsite areas that drain to the site; include maps showing the drainage area boundaries and sizes in acres, topography and typical overland flow directions, and show all existing, interim, and proposed drainage infrastructure and their intended direction of flow. Hydrologic calculations for the Pine Tree Creek watershed.

d. Hydraulics - Provide hydraulic calculations to support the selection and sizing of the onsite drainage network, retention facilities and best management practices (BMPs). Design calculations and the results of the hydraulic backwater model for the Pine Tree Creek diversion channel shall be included.

e. Channel Stabilization Plan – The Project Owner shall present methods to mitigate for adverse hydraulic conditions (high velocities, high shear stress, Froude Numbers greater than 0.8) in the proposed diversion channel. Channel plan and profile maps showing water surface elevations, channel slope, bank protection, channel stabilization elements. Levees shall also be identified.

- ***Watercourses and Critical Areas*** – The DESCP shall show the location of all nearby watercourses including washes, irrigation and drainage canals, and drainage ditches, and shall indicate the proximity of those features to the construction site. Maps shall identify high hazard flood prone areas:

  a. FEMA Regulated Special Flood Hazard Areas (Effective floodplain from DFIRM) shall be shown on site as well as upstream and downstream within 2,000 feet from the BSEP property boundary;

  b. Existing Conditions 100-year Floodplain – Shall be continuous with the effective floodplain; and

  c. Proposed (Revised) Conditions 100-year Floodplain – Shall be continuous with the effective floodplain.

- ***Clearing and Grading*** – The plan shall provide a delineation of all areas to be cleared of vegetation and areas to be preserved. The plan shall provide elevations, slopes, locations, and extent of all proposed grading as shown by contours, cross sections, cut/fill depths or other means. The locations of any disposal areas, fills, or other special features shall also be shown. Existing and proposed topography tying in proposed contours with existing topography shall be illustrated. The DESCP shall include a statement of the quantities of material excavated at the site, whether such excavations or fill is temporary or permanent, and the amount of such material to be imported or exported or a statement explaining that there would be no clearing and/or grading conducted for each element of the project. Areas of no disturbance shall be properly identified and delineated on the plan maps.
- ***Project Schedule*** – The DESCP shall identify on the topographic site map the location of the site-specific BMPs to be employed during each phase of construction (initial grading, project element and diversion channel excavation, and construction, and final grading/stabilization). The project schedule shall identify the duration of the temporary diversion of Pine Tree Creek. Separate BMP implementation schedules shall be provided for each project element for each phase of construction.
- ***Best Management Practices*** – The DESCP shall show the location, timing, and maintenance schedule of all erosion- and sediment-control BMPs to be used prior to initial grading, during project element excavation and construction, during final grading/stabilization, and after construction. BMPs shall include measures designed to control dust and stabilize construction access roads and entrances. The maintenance schedule shall include post-construction maintenance of treatment-control BMPs applied to disturbed areas following construction.
- ***Erosion Control Drawings*** – The erosion-control drawings and narrative shall be designed, stamped and sealed by a professional engineer or erosion-control specialist.
- ***Agency Comments*** – The DESCP shall include copies of recommendations, conditions, and provisions from Kern County, CDFG, and LRWQCB.
- ***Monitoring Plan*** – Monitoring activities shall include routine measurement of the volume of accumulated sediment in the onsite drainage ditches, stormwater retention basins, and the diversion channel. Additional monitoring requirements shall be presented in a Desert Wash Mitigation and Monitoring Plan discussed in Condition of Certification BIO-17.
- ***Maintenance Plan*** – The maintenance plan shall identify activities and procedures needed to maintain capacity within the

Pine Tree Creek diversion channel, all onsite drainage ditches, and the offsite drainage ditch that currently diverts flow along the western property boundary. Channel maintenance may include erosion control repairs, bank stabilization, debris removal, grade control, and revegetation. The maintenance plan shall support the objectives of the revegetation-mitigation effort. Maintenance activities must also include removal of accumulated sediment from all retention basins when an average depth of 0.5 feet of sediment has accumulated in the retention basin. The maintenance plan shall be developed for the life of the project.

Verification: The project owner shall do all of the following:

1. No later than 90 days prior to start of site mobilization, the project owner shall submit a copy of the DESCP to Kern County and the LRWQCB for review and comment. A copy shall be submitted to the CPM no later than 60 days prior to the start of site mobilization for review and approval. The CPM shall consider comments received from Kern County.

2. During construction, the project owner shall provide an analysis in the monthly compliance report on the effectiveness of the drainage-, erosion- and sediment-control measures and the results of monitoring and maintenance activities.

3. Once operational, the project owner shall provide in the annual compliance report information on the results of storm water BMP monitoring and maintenance activities.

4. Provide the CPM with two (2) copies of all monitoring or other reports required for compliance with Kern County, CDFG, and LRWQCB.

5. Provide Kern County, LRWQCB and the CPM with quarterly maintenance activity reports for the Pine Tree Creek diversion channel. These reports shall also provide an account of any significant runoff event or bankfull-channel forming event and will describe the channel performance.

SOIL&WATER-6: In accordance with Kern County's Floodplain Management Ordinance and 44 CFR 65.12, the project owner shall prepare all necessary engineering plans and documents to support a Conditional Letter of Map Revision (CLOMR) application submittal to FEMA. The project shall not commence construction in the SFHA until the Kern County receives from FEMA a CLOMR. Following construction the Project Owner shall prepare all necessary documents required for a final Letter of Map Revision (LOMR). The project owner shall use FEMA's Guidelines and Specifications for Mapping Partners for guidance. The project owner shall:

a. Prepare hydrologic analyses to estimate the 10-, 2-, 1-, and 0.2-percent annual chance flood events for the Pine Tree Creek watershed. The analyses would be conducted using numerical models approved by FEMA.

b. Prepare preliminary design drawings for the channel, include: typical channel dimensions, any structural elements required to protect the channel from erosion, and a grading plan for proposed conditions.

c. Conduct hydraulic analyses for existing and proposed conditions;

d. Prepare flood hazard mapping for the existing and proposed conditions. Floodplain mapping shall tie-into the upstream and downstream special flood hazard mapping shown on the effective DFIRM.

e. Provide notification to all adjacent property owners, impacted by the proposed change to the SFHA; and

f. Complete the necessary FEMA MT-2 application forms package and pay all applicable CLOMR review fees. The submittal shall be certified by a professional engineer;

g. Address all FEMA review comments as needed to receive approval of the CLOMR.

Prior to mobilization the Project Owner shall receive confirmation from Kern County that FEMA has issued a CLOMR for the BSEP. The Project Owner shall address all “conditions” in the CLOMR during project construction. Following construction the Project Owner shall:

h. Conduct an As-Built survey of the completed construction;

i. Update the Proposed Conditions Model to reflect the As-Built Revised Conditions and delineate the resulting flood hazard;

j. Complete the necessary FEMA MT-2 application forms package and pay all applicable LOMR review fees. The submittal shall be certified by a professional engineer;

k. Address all FEMA review comments as needed to receive approval of the LOMR; and

l. Notify the CPM that the LOMR has been approved.

Verification: The project owner shall do all of the following:

1. No later than thirty (30) days after receiving notification from FEMA that all required CLOMR or LOMR documents have been received by FEMA, the Project Owner shall notify the CPM that the project is currently being reviewed by FEMA. During the review process the Project Owner shall submit all correspondence between FEMA and Project Owner’s engineer representative responsible for addressing FEMA’s comments.

2. Prior to construction activity within the SFHA the Project Owner shall provide a copy of the CLOMR to the CPM for verification.

3. Following construction of the channel improvements the Project Owner shall complete an As-built survey of the improvements, update the hydraulic model, and prepare a final submittal for a LOMR. The Project Owner shall submit a copy of completed LOMR submittal to the CPM for review.

4. No later than thirty (30) days after receiving notification from FEMA that the LOMR has been issued to Kern County the Project Owner shall submit a copy of the LOMR to the CPM for verification.

SOIL&WATER-7: The project owner shall coordinate with Kern County to establish a maintenance district for maintaining the integrity, design, and capacity of the Pine Tree Creek diversion channel. The Maintenance District will manage utility crossings of the Diversion Channel and where the linear (gas pipeline) crosses existing drainageways. The maintenance district shall be formed with consideration of all appropriate LRWQCB permit requirements. Maintenance District shall be developed according to the CDFG stream alteration agreement provisions. Funding for the maintenance district shall be provided in perpetuity.

Verification: Prior to completion of the CLOMR submittal the Project Owner shall receive written consent from Kern County allowing BSEP to create a special maintenance district. A copy of the final Maintenance Agreement shall be provided to the CPM for approval and shall include a detailed discussion of the funding mechanism for the channel maintenance. Once operational, the project owner shall provide in the annual compliance report information on the District's monitoring and maintenance activities. The District's reports shall include a discussion of the available funds.

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SOIL AND WATER RESOURCES - APPENDIX A

ACRONYMS USED IN THE SOIL AND WATER RESOURCES SECTION

AF	acre-feet
AFY	acre-feet per year
BFE	Base Flood Elevation
BMP	Best Management Practices
BSEP	Beacon Solar Energy Plant
CalTrans	California Department of Transportation
CDFG	California Department of Fish and Game
CEQA	California Environmental Quality Act
cfs	cubic feet per second
CPM	Compliance Project Manager
CLOMR	Conditional Letter of Map Revision
CSDD	Capitol Storm Design Discharge
CVWD	Coachella Valley Water District
CWA	Clean Water Act
CWC	California Water Code
DESCP	Drainage, Erosion, and Sediment Control Plan
DFIRM	Digital Flood Insurance Rate Map
DTSC	Department of Toxic Substances Control
DWA	Desert Water Agency
DWR	Department of Water Resources
FEMA	Federal Emergency Management Agency
FIS	Flood Insurance Study
FIRMS	Flood Insurance Rate Maps
FSA	Final Staff Assessment
gpd	Gallons per day
gpm	gallons per minute
IEPR	Integrated Energy Policy Report
KCWA	Kern County Water Agency
LORS	laws, ordinances, regulations, and standards
mg/l	milligrams per liter
MW	megawatt
MWD	Metropolitan Water District of Southern California
NFIP	National Flood Insurance Program
NOI	Notice of Intent
NPDES	National Pollutant Discharge Elimination System
NRCS	National Resources Conservation Services
NWS	National Weather Service
NOAA	National Oceanic and Atmospheric Administration
Porter-Cologne	Porter-Cologne Water Quality Control Act
PSA	Preliminary Staff Assessment
RCRA	Resource Conservation and Recovery Act
RWQCB	Regional Water Quality Control Board
SFHA	Special Flood Hazard Area

SPRR	Southern Pacific Railroad
SSG	Solar Steam Generator
STG	Steam Turbine Generator
SWP	State Water Project
SWPPP	Storm Water Pollution Prevention Plan
SWRCB	State Water Resources Control Board
TDS	total dissolved solids
USACE	U.S. Army Corps of Engineers
USDA	U.S. Department of Agriculture
USGS	U.S. Geological Survey
WQMP	Water Quality Management Plan
WSP	Water Supply Plan
WWTP	wastewater treatment plant
ZLD	zero liquid discharge

SOIL AND WATER RESOURCES - APPENDIX B

OVERVIEW OF MODELING APPROACH AND KOEHN LAKE SUB-BASIN MODEL REVIEW

The proposed Beacon Solar site is located in the Koehn sub-basin, which is part of the larger Fremont Valley Groundwater Basin located in the Mojave Desert and northeast of Antelope Valley, southeastern California. Environmental Simulations, Inc. (ENSR, March 2008b) developed a two-dimensional groundwater-flow model of the Koehn sub-basin to evaluate potential pumping impacts as part of the proposed Beacon Solar Energy Project (herein referred to as the "Koehn sub-basin model" or "the model"). Specifically, the model simulated groundwater level changes in response to pumping from extraction wells for plant construction (5-month simulation) and plant operation (30-year simulation). This appendix assesses model construction, assumptions, parameters, calibration, sensitivities, and simulated results.[1]

BACKGROUND ON GROUNDWATER-FLOW MODELING

The process of numerical groundwater-flow modeling involves first developing a conceptual model of the physical system and then applying a mathematical model to represent it quantitatively. A conceptual model is a clear, qualitative description of the natural system and its operation including water sources (recharge), flow directions, and sinks (discharge). The conceptual model of the Koehn sub-basin is based largely on the work of Koehler (1977), and was summarized by ENSR in the Application for Certification (March, 2008a).

A mathematical model utilizes equations to simulate the physical processes described by the conceptual model. The potential complexity of processes and variety of boundary conditions require numerical procedures to determine an approximate solution to the mathematical groundwater-flow equations. The Koehn sub-basin model utilizes the numerical mathematical model MODFLOW 2000 (Harbaugh and others, 2000), which is an updated version of the U.S. Geological Survey's groundwater-flow model MODFLOW. MODFLOW was originally published and distributed in the 1980's, and is widely accepted and used and verified to produce numerically stable solutions (Anderson and Woessner, 1991).

[1] The terms "verification" and "validation" are often used interchangeably in hydrologic modeling. Some consider a "valid" groundwater-flow model as meaning it has been adequately demonstrated that the model simulates the cause and effect relationships within a specific groundwater basin. For example, the model adequately simulates the magnitude and distribution of water level changes in response to a change in recharge and pumpage. This type of validation is typically accomplished by conducting a postaudit after the modeling study is completed. A postaudit assesses whether conditions predicted by the model is confirmed by new field data that has been collected. This type of validation is beyond the scope of our evaluation; rather, we instead consider a "valid" model as a model constructed with an accepted computer code, reasonable parameter values supported by field data, and appropriately defined and implemented boundary conditions. An application is "valid" when all simulations meet typical measures of numerical accuracy (i.e., acceptable mass balance errors and groundwater-level closure criterion) and considers the potential sensitivity of model results to uncertainty in the input parameters.

In applying models to real world groundwater-flow systems, errors can potentially arise from the following sources:

- Conceptual deficiencies (i.e., erroneous basin geometry, incorrect boundary conditions, neglecting important processes, including inappropriate processes, and so forth),
- Numerical deficiencies from errors associated with the equation solvers. These errors introduce problems with computational accuracy and precision, and
- Inadequacies in parameterization (water transmitting and storage properties) and poorly defined stresses (inflows and outflows like recharge and pumping).

The most common errors in model construction are attributed to conceptual deficiencies, inadequate parameterization and poorly defined stresses. The focus of this assessment is: (1) the modeling approach employed to simulate pumping impacts; (2) the assumptions, parameter values, and boundary conditions incorporated into model construction; and, (3) the simulation results and their inherent sensitivity to uncertainty in model input.

CONCEPTUAL MODEL

The Koehn sub-basin is bounded by low permeability rocks and faults, which act as partial barriers to water movement and limit the exchange of groundwater between adjoining sub-basins of the Fremont Valley Groundwater Basin. In the south, the Koehn sub-basin is bounded by the Rand Mountains and Randsburg-Mojave Fault; to the east by the confluence of the El Paso and Rand Mountains; to the north by the El Paso Mountains and Sierra Nevada; and, to the west by the Oak Creek sub-basin. The Koehn sub-basin is further divided by the Cantil Valley Fault and the Garlock Fault. The Cantil Valley Fault is the most hydrologically significant because it acts as a partial barrier to ground-water movement and effectively splits the Koehn sub-basin into two halves that are only partially connected (Koehler, 1977).

In the Koehn sub-basin, percolation of runoff from the mountains and possibly subsurface inflow from the Antelope Valley are the primary sources of groundwater recharge (See **SOIL & WATER FIGURE 3**). Under pre- and early area-development conditions, groundwater flow was from the sub-basin boundaries inward toward Koehn Lake, which is the lowest point within the sub-basin and is the primary natural discharge feature. Since the 1950's, evapotranspiration of groundwater extracted by wells increased and this consumptive use reportedly peaked at almost 60,000 acre-feet per year in the mid- 1970's (Koehler, 1977). These groundwater extractions resulted in substantial groundwater storage reductions in the sub-basin. During the 1980's, groundwater extractions largely ceased and groundwater levels and storage volumes have since somewhat continuously increased (SAMDA Inc., 1997; ENSR, March 2008b). The water level increase is localized recovery from substantial past pumping drawdown, where the recovery is provided by lateral inflow from other parts of the sub-basin and continued recharge.

MODEL CONSTRUCTION

ASSUMPTIONS

We reviewed ENSR's modeling assumptions and found that most are generally consistent with published descriptions of the conceptual model for the Koehn sub-basin and the objectives specified for the numerical groundwater-flow model. The assumptions used in the model included:

- Groundwater in the Koehn Lake sub-basin is unconfined;
- For modeling purposes, vertical groundwater flow in the saturated zone is ignored and the Koehn Lake sub-basin was represented as a two-dimensional system where flow is exclusively in the horizontal (x-y) plane;
- Faults act as partial barriers to groundwater flow, and are represented in the model as thin, vertical, low-permeability geologic features located at the boundary between two adjacent finite-difference cells;
- Groundwater recharge is primarily from mountain-front recharge and infiltration of storm-runoff into stream beds; and,
- Aquifer compaction and land subsidence is neglected because water levels in the sub-basin have been increasing, and Earth Satellite Corporation (SAMDA Inc., 1997) concluded the likelihood of subsidence due to groundwater extraction at the proposed project site was small owing to a relative lack of significant clay layers beneath the water table and unconfined groundwater conditions.

However, staff's review of relevant published modeling studies and data provided by the project applicant indicated some assumptions may be incorrect. The relevant assumptions include two simulated boundary conditions (Antelope Valley inflow and discharge to Koehn Lake), recharge processes, and storage coefficients. Numerical convergence issues were also experienced with some simulations.

- Groundwater inflow across the southern boundary is assumed to be constant (1,000 acre-feet per year), but staff concluded this is inconsistent with groundwater use conditions in California City and fluxes determined by an Antelope Valley groundwater basin modeling study completed in 2003. This is discussed in greater detail below under "*Boundary Conditions-Constant Flux*";
- The model employs drain cells to simulate groundwater discharge from Koehn Lake. The simulated discharge ceases by 1976, which staff concluded may disagree with the reported conceptual model and reported hydrogeologic conditions. This is discussed in greater detail below under "*Boundary Conditions-Fixed Head*";
- The magnitude, distribution, and timing of recharge may be influenced by agricultural return flows and unsaturated zone thickness. This process is not considered by the project applicant's model, and the consequences of this potential conceptual deficiency is discussed in greater detail below under "*Recharge and Pumping*";
- The model assumes that water removed from storage is discharged instantaneously with decline in head, and the storage coefficients do not vary with time. However, staff's review of pumping test results and modeling analyses reported by the project applicant suggest a time-delay in the dewatering response to water level declines,

and therefore storage coefficients may not be constant but instead vary with time (March, 2008b). This deficiency is discussed in greater detail below under "*Storage Coefficient*"; and,

- The model simulations are assumed to converge when the residuals in hydraulic head and volumetric fluxes meet the user's specified criteria. The Koehn sub-basin model appropriately employs a water level closure criterion of 0.001 foot and mass balance error criterion of less than 0.1 percent. However, staff's implementation of the model indicated that not all time-steps of all simulations converged. This deficiency is discussed in greater detail below under "*Results*".

PARAMETERS

The two aquifer properties specified in the model are hydraulic conductivity and storage coefficient (specific yield). Hydraulic conductivity is a measure of the rate of flow through a strip of aquifer of unit height and width under a unit hydraulic gradient. The storage coefficient is the volume of water an aquifer releases or takes into storage per unit surface area per unit change in groundwater level. In unconfined aquifers, the storage coefficient is the specific yield, which is a measure of the water drained from the saturated aquifer material under the force of gravity.

Hydraulic Conductivity

Hydraulic conductivity is a measure of the aquifer's ability to transmit water. There is almost always uncertainty in the magnitude and distribution of hydraulic conductivity owing to the inherent uncertainty of natural heterogeneous systems.

The initial modeled hydraulic conductivity distribution was based largely on Koehler (1977), with refinements based on model calibration to short-term aquifer tests and various water level records in wells during the period 1958 to 2007 (ENSR, 2008b)[2]. Koehler (1977) approximated transmissivity from specific capacity[3] data, from which hydraulic conductivity was calculated using an assumed saturated aquifer thickness. The conductivity values inferred from Koehler's (1977) transmissivity estimates range from 11.5 to almost 31 feet per day (ft/day) (ENSR, October 2008).

In the Koehn sub-basin model, the calibrated conductivity values range from 0.11 to 68.8 ft/day. Except for the lowest conductivity values (0.11 to 0.52 ft/day), the remaining calibrated values (20.0 to 68.8 ft/day) are within about 50-percent of the values inferred from Koehler's (1977) transmissivity estimates (11.5 to 31 ft/day), and

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[2] As reported by ENSR (December, 2008), pumping wells were added and specific yield adjustments were made to improve the match (calibration) between observed and simulated conditions. In their December 2008 document, ENSR provided sensitivity test results for recharge (annual recharge of 10,000 and 25,000 acre-feet per year) showing simulated drawdown contours. However, updated drawdown contour maps for the two prediction simulations (5-month construction and 30-year annual operation) were not provided. Maps reporting drawdown contours using the updated model to uncertainty in hydraulic conductivity (0.5 and 2.0 times hydraulic conductivity), specific yield (0.5 and 2.0 times specific yield), and faults (existence and absence of select faults) were also not provided.

[3] Specific capacity is the yield of water from a well, typically in gallons per minute, divided by the associated water level drawdown, in feet. Specific capacity is influenced by the pumping rate, duration of pumping, well construction, well age, and other factors.

are generally similar to unconfined aquifer zone conductivity values reported by Leighton and Phillips (2003) for the nearby Antelope Valley Groundwater Basin (2 to 30 ft/day). The spatial distribution of calibrated conductivity values in the Koehn sub-basin model are reversed from Koehler's (1977) estimate; the calibrated hydraulic conductivity values north of the Cantil Fault (20 ft/day) are approximately one-half the calibrated conductivity values south of the Fault (68.8 ft/day).

ENSR (October, 2008) acknowledge model conductivity values south of the Cantil Fault are greater than estimated from Koehler's (1977) transmissivity results. They reasoned that uncertainty in aquifer thickness and specific capacity data could explain the differences. ENSR (October, 2008) concluded that model results may be more reliable than Koehler's (1977) results because they represent values averaged over a greater basin area than specific capacity data from individual wells. However, staff's experience with groundwater flow models indicates that calibrated conductivity values are coupled to specified stresses, and therefore uncertainty in the magnitude and distribution of simulated pumping and recharge contribute to uncertainty in modeled hydraulic conductivity. The AFC reports that modeled pumping and recharge are only approximate values, and therefore the reliability of calibrated hydraulic conductivity is similarly uncertain.

The two largest conductivity zones represent the area north and south of the Cantil Valley Fault (conductivity zones 1 and 2, respectively, as reported by ENSR, March 2008b). The modeled hydraulic conductivity distribution is uniform and continuous throughout these zones, even for the areas beneath Koehn Lake. Staff concluded this representation is inconsistent with the sub-basin's geologic description provided in the AFC (March, 2008) indicating that sediment texture fines towards the lake and that five deep borings in the lake bed found predominantly clay sediments to a depth of 515 below ground surface. These descriptions suggest that hydraulic conductivity is not uniform, but instead significantly decreases with the increased fining of sediment texture toward the lake. The departure of the numerical model from the conceptual model may influence temporal trends in the magnitude and rate of simulated groundwater discharge to the lake (groundwater discharge to Koehn Lake is discussed in greater detail below under "*Boundary Conditions*").

The lowest calibrated model-conductivity values are located beneath the northern portion of the proposed project site (0.11 ft/d), and beneath the eastern end of the modeled valley (0.40 to 0.52 ft/d). Model calibration to short term pumping test data was used to determine site specific conductivity values, and the low values beneath the proposed project site seem to correspond to areas mapped by Earth Satellite Corporation (SAMDA Inc., 1997) as having significant surficial clay deposits and more frequent and thicker clay lenses with depth. In the eastern end of the valley, no specific capacity or aquifer test data is provided to confirm the lower calibrated conductivity values that were reportedly necessary to simulate high water levels in the area (ENSR, 2008b). A map showing model-calibration target locations (ENSR, October 2008, Figure DR-106) does not include the low conductivity zones modeled in the northeastern end of the valley, nor do the 1958 water level contours reported by Koehler (1977) extend into these zones. It is not clear to staff what constraints were relied on to calibrate the conductivity values in the eastern end of the valley.

Due to uncertainty in hydraulic conductivity, the model simulations reported by ENSR consider a range in hydraulic conductivity. Uncertainty was considered by conducting parallel simulations that uniformly multiplied hydraulic conductivity values by factors of 0.5 and 2.0 (ENSR, October 2008).

Storage Coefficient

The storage coefficient relates the volume of water released per unit area of aquifer to a unit decline in head. In an unconfined aquifer, the storage coefficient is represented by the specific yield. Koehler (1977) estimated a specific yield for the Koehn sub-basin of 0.11 based on well-driller logs, which is the value employed in the model.

Similar to hydraulic conductivity, there is uncertainty in the magnitude and distribution of specified yield. The model assumes that the water removed from storage is discharged instantaneously with a decline in water level, and the storage coefficient therefore is constant and does not vary with time. Pumping test data analyses conducted with model and reported by ENSR (March, 2008b) indicate short-term storage coefficients on the order of 10^{-3} for most of the model area and 10^{-4} for the central part of the project site. These storage coefficient values were determined from short-term tests (on the order of several days) and are substantially lower than the specific yield employed in the model (0.11). ENSR (2008b) concluded the small storage coefficients indicated semi-confined to confined aquifer conditions, which is inconsistent with the conceptual model (the sub-basin is considered an unconfined aquifer system). Alternatively, the small storage coefficients from short-term pumping tests may indicate groundwater releases slowly from storage as water levels decline. The delay in yield would indicate storage changes are not instantaneous, but instead are a time-dependent process. Significant time may be required to drain the water from storage between sediment grains at amounts that are consistent with the specific yield.

If the pumping test results indeed reflect delayed yield, the assumption that storage releases instantaneously is probably reasonable for long-term simulations (i.e., simulations that consider water level changes over a 30-year period). However, the simulated water level response to shorter pumping periods (i.e., simulations that consider water level changes over a period of several days or weeks) can be under-estimated using the specific yield. If, rather, the pumping test results indicate semi-confined to confined aquifer conditions, the conceptual model is wrong andspecific yield should not be used to simulate drawdown.

Due to uncertainty in the storage coefficient, the model simulations reported by ENSR consider a range in specific yield. The uncertainty was considered by conducting parallel simulations that multiply specific yield values by factors of 0.5 and 2.0 (ENSR, October 2008).

Faults

The Horizontal Flow Barrier Package simulates the hydrologic effects of internal faulting within the Koehn sub-basin. It represents faults as thin, vertical, low-permeability geologic features located at the boundary between two adjacent finite-difference cells.

The parameter representing the fault is its hydraulic characteristic, in units of per day (day^{-1}); the hydraulic characteristic is the barrier hydraulic conductivity (ft/day) divided by its width (ft).

In the Koehn sub-basin model, four faults are simulated (the Garlock, Cantil Valley, Randsburg-Mojave, and Muroc Faults). With the exception of the Garlock Fault, the calibrated hydraulic characteristics range from about 4×10^{-5} to 2×10^{-3} day^{-1}, which is generally similar to the range in unconfined zone fault hydraulic characteristics reported by Leighton and Phillips (2003) for their model of the Antelope Valley (1.0×10^{-5} to 4.0×10^{-3} day^{-1}). The calibrated hydraulic characteristic for the Garlock Fault is considerably higher than the other three faults (1.0 day^{-1}).

Due to uncertainty in fault hydraulic characteristics, ENSR (October, 2008) reported model simulations that tested model sensitivity to select faults by reporting two parallel simulations; one simulation appears to have removed the Cantil Valley Fault, and the second appears to have removed the Randsburg-Mojave Fault.

BOUNDARY CONDITIONS

The model utilizes three types of boundary conditions: free-surface, constant-flux, and fixed-head (general-head and drain).

Free-Surface

The free-surface boundary condition simulates the water table, which intercepts recharge and subsequently rises and falls in response to simulated recharge and pumping. The model does not explicitly simulate the contribution of irrigation return flows to the magnitude and distribution of recharge, and does not consider potential delays in the timing of irrigation return flows owing to the thick unsaturated zone. These issues are discussed below beneath the heading "*Recharge and Pumping*".

Constant-Flux

Groundwater flow across the southern boundary is assumed to be constant (1,000 acre-feet per year) and independent of water level differences between the Antelope Valley groundwater basin and Koehn sub-basin. Staff reviewed published Antelope Valley groundwater modeling studies and concluded the specified constant inflow of 1,000 acre-feet per year (AF/yr) is inconsistent with these previous studies.

ENSR (March, 2008a and 2008b) cites Durbin (1978) as the source for a specified inflow of 1,000 AF/yr. Durbin's (1978) estimate represents subsurface flow from Antelope Valley into the Fremont Basin through a gap in the bedrock located southeast of California City (a gap in the bedrock located at the northwest corner of the north Muroc groundwater sub-basin). However, staff's review of model boundary conditions reported in the AFC indicated the Koehn sub-basin model introduces this flow at a location northwest of California City. Figure 5.17-5 of the Application for Certification (Groundwater Recovery Rates, Koehn sub-basin) shows water levels in the vicinity of California City are declining (ENSR, March 2008a). Hence, staff concluded that subsurface flow entering the model southeast of California City is probably captured, at least partially, by extraction wells in the California City sub-basin prior to reaching the Koehn sub-basin model boundary located northwest of California City – if it reaches it at all.

Phillips and Leighton (2003) reported that the gradient from the Antelope Basin to the Fremont Basin has not been constant over time, and therefore subsurface inflow to the Koehn sub-basin, if any, is not constant over time. Furthermore, the magnitude of their flow estimate is substantially less than Durbin's (1978) estimate of 1,000 AF/yr. Phillips and Leighton (2003) reported that subsurface inflow to the Fremont Basin was about 5400 AF/yr in 1958, and declined to 200 AF/yr by 1995. If these trends continued after 1995, the inflow probably declined to a value significantly less than 200 AF/yr by 2007.

Staff's review of the AFC indicated that no information was provided to assess the sensitivity of model results to the magnitude of specified inflow. Staff attempted to test the sensitivity of the calibrated model to specified inflow, but the altered model would not converge.

Fixed-Head

Two types of fixed-head boundaries are employed in the model: a general-head boundary along the eastern edge of the model simulates subsurface inflow across the Muroc Fault, and a drain boundary that simulates groundwater discharge to Koehn Lake.

The general-head boundary assumes the exchange of water across the Muroc Fault is proportional to the difference between a specified external water level west of the Fault (presumably located within the Chaffee sub-basin) and the model-calculated water levels in the adjacent portion of the California City sub-basin. The external water level is specified at 2,430 feet above mean sea level. The proportionality constant (the general head boundary conductance) represents the effective hydraulic conductivity across the fault and between the two sub-basins, and the distance to the specified external water level. Because the specified external water levels are maintained constant, they assume water levels within the Chaffee sub-basin are stable and simulated flow across the Murock Fault is solely dependent on model-calculated water levels in the California City and Koehn sub-basins. Based on the model output listing file (ENSR, October 2008), simulated flow across the Muroc Fault increases from 696 AF/yr in 1959, to 704 AF/yr in 2007[4].

Groundwater discharge from Koehn Lake is the primary discharge mechanism under pre- and early-development conditions. Groundwater discharge across the lake bed is simulated using drain boundaries, which assume leakage to the drain is proportional to the difference between model-calculated groundwater levels and the specified drain elevation (the drain elevation is considered equal to the lake bed elevation). The proportionality constant, or drain conductance, is determined by the properties of the interface between the lake bed and deeper groundwater system.

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[4] The simulated general-head boundary inflow in the December 2008 calibration is slightly different from the October 2008 version; in the more recent version, inflow increased from 707 AF/yr in 1959, to 709 AF/yr in 2007.

In the historical calibration run (ENSR, October 2008), simulated drain flow (groundwater discharge to Koehn Lake) ceases by 1976, which disagrees with Table DR-112W indicating present-day discharge ranges from 2,800 to 3,000 AF/yr.[5] Several pieces of reported evidence also seem to indicate continued groundwater discharge to Koehn Lake under present day conditions:

- Potentiometric maps prepared by Earth Satellite Corporation for 1985 and 1997 (Figures F.2 and F.3, respectively) continued to show groundwater gradients toward Koehn Lake (SAMDA Inc., 1997).
- Figure 116W (ENSR, December 2008) indicates observed groundwater levels in well 30S/38E-24F01 are currently about equal to the lake bed, suggesting groundwater discharge may be occurring.
- Figure 116W (ENSR, December 2008) shows two wells located relatively close to each other (30S/38E-31C01 and 30S/38E-30Q01), but there is an almost 50-feet difference in their well-water levels; ENSR (2008) reported that depth and construction information is not available for these wells. The latter well has observed water levels about equal to the lake bed elevation, indicating potential discharge to the lake; whereas, the former well has observed water levels substantially below the lake bed elevation. Hence, there is considerable spatial variability in water levels between wells, and data from existing wells may be limited for determining groundwater discharge conditions relative to Koehn Lake.

In the Koehn sub-basin model, Koehn Lake is located within two large conductivity zones (one north and one south of the Cantil Valley Fault). The conductivity zones are shown on Figure 4.3 of Appendix J.2 of the Application for Certification (ENSR, March 2008a). The model does not represent the observed reduction in coarse-grained sediment thickness and effective hydraulic conductivity beneath the lake. ENSR (2008a) cited studies that reported sediment texture fines towards the lake, and five deep borings in the lakebed found predominantly clay sediments to a depth of 515 below ground surface. This deviation from observed conditions may influence the magnitude and timing of simulated groundwater discharge to Koehn Lake.

RECHARGE AND PUMPING

Simulated average, annual recharge is 15,000 AF/yr.[6] Simulated recharge represents mountain-front recharge and infiltration of storm-runoff into stream beds. This recharge rate was estimated from previous studies (Koehler, 1977; Bloyd, 1967; Welch and Bright, 2007) and an analysis of historical precipitation and run-off potential (ENSR, March 2008a). ENSR concluded mountain-front recharge and infiltration of storm-runoff into stream beds could range from 3,000 to 22,000 AF/yr. Due to uncertainty in recharge, reported model simulations assumed recharge ranges from 10,000 to 25,000 acre-feet per year.

[5] In the updated calibration reported by ENSR (December, 2008), discharge from the lake ceases after 1974 (one year earlier than the calibration run reported in October, 2008).

[6] In the updated calibration reported by ENSR (December, 2008), simulated recharge is greater and equal to almost 15,700 AF/yr.

During the period 1959 to 2007, simulated annual pumping rates range from 840 to 60,840 AF/yr.[7] During the period 1960 to 1976, historical annual pumping rates are based on Koehler's (1977) annual consumptive use estimates. After 1976, annual pumping rates included estimated domestic, industrial, and agricultural water uses (agricultural pumping was estimated from irrigated land areas identified by field surveys and aerial photographs).

The model relies substantially on Koehler's (1977) reported annual consumptive use estimates for simulated pumping rates. Koehler (1977) defines consumptive use as being equivalent to evapotranspiration, which is not the same as the applied water or pumpage. Water application rates are usually greater than consumptive use rates because some of the applied water is lost to deep percolation past the plant roots, evaporates from bare surfaces, and so forth. Leighton and Phillips (2003) estimated that 30-percent of the applied irrigation water in the Antelope Valley is not available to the plant and becomes deep percolation to the groundwater system.

The principal crop grown in the Fremont Valley was alfalfa, and Koehler (1977) employed a "consumptive use" rate of 6.2 feet per year (ft/yr). Koehler's (1977) consumptive use rate is higher than plant water use rates reported for alfalfa grown in similar areas. Leighton and Phillips (2003) cited studies that estimated the consumptive use rate for alfalfa in desert areas at 4.8 ft/yr, and a corresponding water application rate for alfalfa of 6.6 ft/yr.

If Koehler's (1977) "consumptive use" estimates in fact represent plant water use, then the volume of water extracted and applied (total pumpage) was substantially greater than 6.2 ft/yr. Conversely, if Koehler's (1977) "consumptive use" estimates actually represent the water applied (total pumpage), then a substantial proportion of the 6.2 ft/yr of applied water (approximately 30-percent) percolated past the crop roots and was returned to groundwater storage (agricultural return flow). In either case, based on this information staff concluded that potentially important processes (agricultural return flows) and the relationships between total pumpage and groundwater recharge may not be considered by the model.

Staff recognizes it could be argued that the Koehn sub-basin is a one-layer model, and the appropriate input to evaluate is the difference between total pumpage and return flows (net pumpage), which is essentially the water consumed by the plants. However, the analysis of Leighton and Phillips (2003) indicates there is a time lag between when water is applied and when it reaches the water table. Specifically, they employed a 10-year delay for agricultural return flows to percolate through the thick unsaturated zone and reach the water table. Including this time delay will alter the time-series of net pumpage in the model, which could have an influence on calibrated model parameter values.

[7] In the updated calibration reported by ENSR (December, 2008), simulated annual pumping rates range from 4,100 to 66,115 AF/yr.

CALIBRATION

The purpose of calibration is to establish that the model reproduces observed real-world groundwater levels and flows. During model calibration, model parameters like hydraulic conductivity and storage coefficient are systematically adjusted in an attempt to improve the match between simulated and observed groundwater levels and flows. The result is an improved description of the magnitude and distribution of hydraulic conductivity and storage coefficient in the groundwater system.

All calibrated models are influenced by uncertainty because we cannot define the distribution of parameters like hydraulic conductivity and storage coefficient exactly. There is also uncertainty in the definition of boundary conditions, and uncertainty in the magnitude, distribution and timing of stresses like recharge and pumpage. For these reasons, a sensitivity analysis is performed to assess and quantify the effect of uncertainty on model calibration and predicted water levels simulated by the model. The model simulations reported by ENSR included sensitivity tests conducted on hydraulic conductivity, storage coefficient (specific yield), fault conductance, and recharge. The sensitivity test results were reported as contours of simulated drawdown after 30 years of pumping from Well 48, and hydrographs showing simulated and observed water levels during the historical run.

RESULTS

CALIBRATION

The data input files for the historical calibration run were received from ENSR in October 2008, and we ran the model in DOS using executable files obtained from the U.S. Geological Survey's Water Resource Divisions website (MODFLOW Version 1.15.00, 8/6/2004). The model as provided did not converge, but we achieved convergence in all time-steps after changing the damping factor from 1.0 to 0.9.[8] We compared the listing output file with the parallel listing file provided by ENSR and noted the differences between simulated volumetric budgets are negligible. We did not check for differences in simulated water levels, but presumed they also were negligible.

The calibrated historical model reported by ENSR (October 2008) indicates that after 1996 groundwater storage has been increasing at an average annual rate of almost 14,300 AF/yr.[9] Accordingly, simulated groundwater levels have also steadily increased through the end of the simulation in 2007.

[8] In December 2008, ENSR provided updated data input files for the historical calibration run. The updated model did not converge. Convergence was achieved by increasing the outer iterations from 100 to 200 and adjusting the damping factor from 1.0 to 0.85.

[9] In the updated calibration reported by ENSR (December, 2008), the simulated annual storage increases after 1996 averaged about 10,000 AF/yr. The storage change simulated by the updated model is more than 4,000 AF/yr less than simulated by the October 2008 version of the historical calibration. The updated calibration run provided in December 2008 is therefore significantly different from the version provided by ENSR in October 2008.

PREDICTIONS

The data input files for the 5-month and 30-year prediction runs[10] were received from ENSR in October 2008, and we ran the model in DOS using executable files obtained from the U.S. Geological Survey's Water Resource Divisions website (MODFLOW Version 1.15.00, 8/6/2004). The models as provided converged in all time steps.

ENSR (March, 2008) reported model simulation results for groundwater pumping and use owing to project construction and project operations. Project construction is expected to take place over a period of about 26 months, but the most intensive pumping will occur during the first 5 months as the site is prepared and graded. Actual project operations are planned to begin about 21-months after grading and site preparation, during which time a small amount of pumping will continue (about 9 AF per month or less). At the end of the 26-months, project operations are expected to use at most 1,600 AF/yr of groundwater.

Five-Month Construction Pumping

Water usage during site preparation and grading was simulated by the model. The simulated pumping schedule consisted of 112.5 AF the first month (month 1), 225 AF during the next four months at an average rate of 56.25 AF per month (months 2-4), and 112.5 AF during the final month (month 5). The total pumpage during the 5-month site preparation and grading period was 900 AF.

ENSR (March 2008a) reported simulated drawdown from pumping during the site grading period. The contours indicate maximum drawdown in excess of 10 feet beneath the proposed project site. Comparisons between water supply well locations from ENSR's field survey (Figure 5.17-13) and the simulated drawdown map indicate 2 single family wells located northwest of the property are impacted by about 5-feet of drawdown owing to site grading water use. Depending on the magnitude of influence from delayed yield, the short-term drawdown could be greater.

Thirty-Year Project Pumping

For project operations, 1,600 AF/yr of pumping was simulated for a continuous 30-year period (ENSR, March 2008b). Later submittals by ENSR (October, 2008 and December, 2008) reported the sensitivity of model simulation results to aquifer parameters (specific yield and hydraulic conductivity), fault hydraulic characteristics, and recharge. The model results are reported in map form showing simulated drawdown contours and water supply well locations. We summarized these maps by totaling the number of wells impacted by water level declines of 5 feet or more and report the results below in **Soil and Water Table B1**.[11] Water levels in a substantial

[10] Data input files for the 5-month and 30-year prediction runs were not provided in December 2008 with the updated model. We therefore created these runs using the updated model input files and integrating the necessary changes to the time discritizaton and well input files to mimic the October versions of these runs. The model converged in all time-steps for both runs.

[11] The water well and groundwater level data base reported by ENSR (March, 2008a) includes about 160 wells, and the average well depth is 430 feet; the average reported perforated interval is 250 feet. The average depth of water supply wells on the plant site is about 850 feet, and the average perforated interval is 520 feet.

number of public and private wells are potentially impacted by project groundwater use. The results in **Soil and Water Table B1** represent minimum impacts because model simulations do not consider residual drawdowns from site construction water use and their potentially additive effect on long-term drawdown. As a test, we combined the 5-month and 30-year prediction runs and determined that by including residual drawdown from construction water use, the drawdown at some wells after the 30-year operation period could increase by almost 8 feet (the average additional drawdown at all wells is almost 1 foot).

Soil and Water Table B1
Summary of Impacts Projected by Calibrated Model and Sensitivity to Select Parameters and Stresses

Model Run	Mapped Wells Having Simulated Drawdown Greater Than or Equal to 5 feet After 30 Years of Pumpage						Drawdown Less than 5 Feet	Total [a]
	Agricultural	Industrial	Multiple Family	Single Family	Municipal	Subtotal		
Calibrated Model	1	3	1	14	1	20	9	29
½ specific yield	1	3	1	13	0	18	11	29
2 specific yield	0	3	1	3	0	7	22	29
½ hydraulic conductivity	1	3	1	14	0	19	10	29
2 hydraulic conductivity	0	3	1	3	0	7	22	29
Recharge = 10,000 af/yr	0	3 [b]	1	12 [b]	0	16	13	29
Recharge = 25,000 af/yr	0	3 [b]	1	8 [b]	0	12	17	29
Remove Fault [c]	0	5	1	5	1	12	17	29
Remove Zone 2 [d]	1	3	1	12	0	17	12	29

a: Total number of wells shown within the reported map extent – not necessarily the total number of wells identified in the Koehn sub-basin.

b: The maps prepared by ENSR have different extents, and as a result wells visible on one map may not be visible on another. We therefore estimated the simulated impacts by projecting the contours into the excluded areas where other maps show a well is located.

c: Assumed only the Cantil Fault was removed from the model per Table 4.1 (ENSR, March 2008b).

d: Assumed Zone 2 refers to the Randsburg-Mojave Fault per Table 4.1 (ENSR, March 2008b).

In terms of the number of wells affected, the 30-year project simulation using the calibrated model resulted in the greatest number of impacted wells (20). Model results indicate that 20 wells located within a distance of about 4 miles of the simulated pumping well (Well 48) are reduced by 5 feet or more after 30 years of pumping relative to expected conditions without project groundwater use. However, **Soil and Water**

Table B1 considers only the number of wells affected by 5 feet or more of drawdown, and does not reflect relative differences in the magnitude of drawdown. For example, both the "Remove Fault" and "Recharge = 25,000 AF/yr" simulations indicate that 12 wells are affected by 5 feet or more of drawdown after 30-years of pumpage. However, the cone of depression is generally steeper for the latter simulation, and 3 wells are affected by 10 feet or more of drawdown. In contrast, the "Remove Fault" simulation indicated only 2 wells are affected by 10 feet or more of drawdown.

CONCLUSIONS

The Koehn sub-basin model employs a verified computer code (MODFLOW) that is widely used and an appropriate application for this evaluation. The specified aquifer parameters and most boundary conditions appear generally consistent with the published conceptual groundwater system (California Department of Water Resources, 2004; Koehler, 1977; and others). However, staff identified potential problems with two boundaries specified in the model (Antelope Valley inflow and discharge to Koehn Lake). Staff also concluded that the calibration constraints for hydraulic conductivity in the eastern portion of the sub-basin are not clearly identified, and important recharge processes may be neglected in the model (agricultural return flows). Model testing conducted by staff showed that some model simulations failed to converge without adjustments to the numerical solver package, but the lack of convergence did not appear to significantly influence model results.

The key findings and outstanding issues identified by our assessment are summarized below.

1. The model utilizes a specified constant inflow of 1,000 acre-feet per year (AF/yr), but previous Antelope Valley groundwater basin modeling studies reviewed by staff suggest the inflow is probably currently less than 200 AF/yr. This inflow enters the Fremont Valley southeast of California City; however the model introduces the flow at a location northwest of California City. Existing extraction wells in the California City sub-basin probably capture this inflow prior to reaching the location represented by the model boundary. As a result, there is probably little to no contribution of subsurface inflow from Antelope Valley to the Koehn sub-basin.

2. The model employs drain cells to simulate groundwater discharge from Koehn Lake. In the historical calibration run (ENSR, October 2008), the simulated discharge ceases by 1976, which disagrees with Table DR-112W indicating present-day discharge ranges from 2,800 to 3,000 AF/yr. Data and analyses presented by SAMDA Inc. (1997) and ENSR (March 2008a; December 2008) also seem to indicate groundwater discharge continued beyond 1976 and important reported hydrogeologic conditions near and beneath the Lake are not represented by the model.

3. Staff's review could not find documentation for the constraints utilized to calibrate conductivity in the eastern valley area represented by the model. A map showing calibration target locations (ENSR, October 2008, Figure DR-106) does not include the conductivity zones representing the eastern end of the valley, nor do the 1958 water level contours reported by Koehler (1977) extend into these zones.

4. The magnitude, distribution, and timing of historical agricultural return flows are not explicitly considered by the model. The analysis of Leighton and Phillips (2003) for the Antelope Valley assumed a 10-year delay for agricultural return flows to percolate through the thick unsaturated zone and reach the water table. Including these processes may influence calibrated model parameters and simulated water level trends.

5. The reported short-term pumping impacts during project grading activities need to be qualified as minimum impacts owing to possible delayed yield effects. Pumping test analyses indicated aquifer storage coefficients vary with time yet the model assumes groundwater releases from storage instantaneously. The assumption is probably reasonable for long-term simulations (i.e., simulations that consider water level changes over the 30-year project period); however the simulated water level response to shorter pumping periods (i.e., simulations that consider changes over a period of several days, weeks or possibly months) may under-estimate the short-term water level decline.

6. The model calibration was updated in December 2008, but a number of previously reported simulations were not updated to reflect changes in modeled-aquifer parameters. Therefore, a lack of consistency exists between simulated impact and sensitivity test model runs summarized in **Soil and Water Table B1**. Specifically, drawdown maps for sensitivity tests on the 30-year project pumping projection need to be updated (½ and 2 times hydraulic conductivity, ½ and 2 times storage coefficient, and removal of faults). If the specified flux boundary condition were modified (see number 4 above), then maps for the 30-year pumping simulation and sensitivity tests on recharge need to be reproduced and reported as well. A table listing impacted wells and maximum simulated drawdown for the above runs would quantify the relative magnitude and differences in drawdown simulated between well locations.

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SOIL AND WATER RESOURCES – APPENDIX C
PROPOSED PINE TREE CREEK WASH DIVERSION CHANNEL HYDROLOGIC ND HYDRAULIC ANALYSIS

OVERVIEW/PURPOSE

The proposed Beacon Solar site is located near the mouth of the Pine Tree Creek watershed in the South Lahontan Hydrologic Region of the Mojave Desert (DWR2003). Pine Tree Creek, which is mapped by FEMA as a Special Flood Hazard Area, crosses the BSEP site. BSEP has proposed an on-site realignment of Pine Tree Creek around the solar plant. Carlton Engineering, Inc. prepared a Conceptual Drainage Study (CDS) to assess drainage patterns associated with the project. The CDS included detailed analyses for the existing and proposed drainage flows through and around the development and provided the basis for design. The CDS was submitted to the California Energy Commission as part of the AFC (BS 2008a). This appendix provides Staff's technical evaluation of the CDS and of potential flood hazard impacts that may result if the project was constructed as proposed in the AFC.

Staff's analyses focused on the following key areas:

- Special Flood Hazard Areas
- Hydrology
- Geomorphic Assessment
- Hydraulics
- Bank Protection
- Grade Control

SPECIAL FLOOD HAZARD AREAS

The Flood Insurance Study (FIS) for Kern County, California and Incorporated Areas (FIS Number 06029CV001A), became effective on September 26, 2008. The county-wide FIS investigates the existence and severity of flood hazards in, or revises and updates previous FISs/Flood Insurance Rate Maps (FIRMs) for the geographic area of Kern County, California and aids in the administration of the National Flood Insurance Act of 1968 and the Flood Disaster Protection Act of 1973. Most of the hydrologic and hydraulic analyses for the original FIS study were conducted in the 1980s. The County's FIS includes flood hazard data in the region of BSEP. This data was used by Staff to evaluate the applicant's floodplain management plan. Minimum floodplain management requirements for participation in the National Flood Insurance Program (NFIP) are set forth in the Code of Federal Regulations, 44 CFR, 60.3. (FEMA 2008).

The effective Digital Flood Insurance Rate Map (DFIRM) was recently developed using a straight conversion from paper maps or Flood Insurance Rate Maps (FIRMs). The method used to convert the Special Flood Hazard Area (SFHA) to the digital format did not include new analyses. The "straight conversion" did not correct for topographic irregularities in the mapping. The result of the effective DFIRM mapping is that there continues to be inconsistencies with the actual flood hazard and the mapped flood hazard. For instance, when comparing the Pine Tree Creek SFHA to the existing channel, staff notes that the mapped floodplain does not always contain the low flow channel. These inaccuracies reflect the limitations of applying the effective floodplain mapping to the BSEP project.

In addition to data retrieved from published FEMA documents, staff collected data from various sources including the National Weather Service; National Oceanic and Atmospheric Administration (NOAA), U.S. Army Corps of Engineers (USACE); U.S. Geological Survey (USGS); National Resources Conservation Services (NRCS), California Department of Water Resources (DWR), California Department of Fish and Game (CDFG), California Department of Transportation (CalTrans); Kern County Water Agency (KCWA), Kern County Planning Department, Public Works Department, and several other sources.

Kern County Water Agency and Kern County Planning Department participate in the Cooperative Stream Gauging Program. The stream gauge at Pine Tree Creek (USGS 10264750) is located13 miles northeast of Mohave, CA. The gauge is located on the downstream side of the Los Angeles aqueduct siphon pier near the right bank. The drainage area at this gauge is approximately 33.5 square-miles. The gauge was established in 1958 by the USGS. Data is available from 1958 through 1976. Another gauge on Cottonwood Creek (USGS 10264770) recorded annually during the period 1967 to 1972. A third nearby gauge is located on Cache Creek which also has less than 10 years of data.

RIVERINE FLOOD HAZARDS

Kern County, due to its large extent and varied geography, has several hundred potential flood sources and approximately one-half million acres of FEMA identified SFHA's. The types of floodplains within the County are very diverse and include riverine floodplains (fast moving channelized flow), distributary flow floodplains (very broad, slow moving, shallow flow), and alluvial fan floodplains (heavily sediment laden, broad, shifting, and rapid moving flow) (FEMA, 2008).

Pine Tree Creek is the principal drainage feature with a high potential for flooding at the proposed BSEP site. Pine Tree Creek originates from the Pine Tree Canyon, which has a drainage area of 33.5 square-miles near the mouth of the canyon. After leaving the canyon, Pine Tree Creek forms and flows across an alluvial fan and crosses beneath SR-14 and the Southern Pacific Railroad (SPRR) tracks before it becomes more of a distributary flow floodplain on the alluvial flat or piedmont where the Beacon site is proposed. The distal terminus of the Pine Tree Creek alluvial fan is near its confluence with Jawbone Creek.

Pine Tree Creek conveys offsite runoff across the property from the south to the northeast. The Federal Emergency Management Agency's effective DFIRM for Kern County (FEMA, 2008) indicates that portions of the BSEP site are within the FEMA designated SFHA 'Zone A' floodplain area. The FEMA SFHA Zone A is the flood insurance rate zone used for 1-percent-annual-chance (base flood) floodplains that are determined for the Flood Insurance Study (FIS) by approximate methods of analysis.

Because detailed hydraulic analyses are not performed for such areas, no Base Flood Elevations (BFEs) or depths are shown in this zone. Mandatory flood insurance purchase requirements apply.
FEMA SFHAs in the Pine Tree Creek watershed are mapped for several miles upstream from its confluence with Jawbone Creek. Upstream of the Beacon property, the SFHAs follow two primary sub-watershed drainage paths: Pine Tree Canyon and the Barren Ridge flats. It is clear from comparing recent aerial photos to the DFIRM mapping (especially along the flats) that the SFHAs do not always coincide with the location of the channels.

HYDROLOGY

BSEP's CDS evaluates pre- and post-development site hydrology for the site and its tributary areas. The results of the CDS were used to provide preliminary design flow rate criteria for the proposed diversion channel and onsite drainage features. BSEP used USDA Natural Resource Conservation Service Technical Release 55 for estimating runoff from the site and from small offsite areas draining the site. This section provides Staff's comments on the onsite and offsite hydrologic analyses from the BSEP CDS. This section also describes regional watersheds near the project and presents a summary of historic flood events. Staff's recommendations for revising the analyses are presented in the Soil & Water impacts analysis section of the PSA.

The goal of staff's review of the applicant's hydrologic evaluation is to provide an assessment of the "reasonableness" of the applicant's proposed base flood discharge estimates and, if necessary, to suggest alternative methods that may provide more reasonable flood discharges. The reasonableness of a flood discharge depends on the study requirements and hydrologic conditions in the region of interest (FEMA 2008).

REGIONAL WATERSHEDS

California Department of Water Resources identified 10 hydrologic regions in California that were delineated based on their similar geographic, climatic, and hydrologic characteristics. The BSEP site is within the South Lahontan Hydrologic Region. The South Lahontan Hydrologic Region has been further subdivided into 78 basins and sub-basins. This analysis primarily evaluates the Pine Tree Creek Watershed located within the Fremont Valley Groundwater Basin. Pine Tree Creek originates at Barren Ridge and Pine Tree Canyon in the Tehachapi Mountains, southeast of the BSEP site.

Pine Tree Canyon drains along an alluvial channel that flows through an existing six cell 8'x8' Reinforced Concrete Box (RCB) culvert at SR-14. Staff estimates this culvert can convey flows of nearly 4,000 cubic feet per second (cfs). The SR-14 culvert outfall forms an artificial hydrographical apex for flows within the culvert's capacity. Flows greater than the capacity of the culvert would simply overtop SR-14. No attenuation of flow is expected in any overtopping event. According to Caltrans, the six cell culvert has not been overtopped since its construction (Aaron Leicht, pers comm., January 6, 2009). Downstream of SPRR, Pine Tree Canyon flows join with runoff from the Barren Ridge area and drain toward the BSEP site. The total drainage area is approximately 83.2 square-miles.

Based on staff's review, a large portion of the Chuckwalla Mountains appears to be tributary to the BSEP site. Staff could not determine the historic offsite drainage patterns from this offsite watershed area. State Route-14 and the SPRR separate the Chuckwalla Mountains sub-watersheds from the BSEP site. Staff has identified several large culvert crossings along SR-14 and SPRR that currently direct runoff from the foothills toward the site. The applicant has identified a ditch located immediately outside of the BSEP's western property boundary that would divert runoff from this area to the north.

A small sub-watershed, having a drainage area of approximately 1.5 square miles, drains to State waters that cross the site from the west. Staff could not validate the mitigation plan for the revised drainageway. Staff reviewed the BSEP proposal to divert the natural drainage swale into a trapezoidal shaped ditch and convey the runoff across the site to the proposed diversion channel. Shed D is described as requiring a ditch capacity for 75.5 cfs. Staff calculated the peak flowrate for this sub-watershed using regional regression equations. The 100-year peak discharge entering the site would range between 700 cfs and 1,100 cfs depending on which regression equation was used. Staff estimates that a ditch with similar design characteristics (Roughness, side slopes, longitudinal slope, etc) would require a bottom width of at least 20 feet and require 3.0 feet of depth plus another foot for freeboard.

BSEP ONSITE HYDROLOGY

Staff's review of the CDS evaluated the methods used to analyze the site runoff. The CDS identified Desert Shrub as the hydrologic cover type for the site. Due to the increase in impervious area from site development, the post development curve numbers were increased approximately 3% from the existing condition curve numbers. Most of the soils across the site are classified in the CDS as Hydrologic Soil Group A, which has a very rapid permeability (6-20 inches per hour). A small portion of the site contains Hydrologic Soil Group D, which has moderately slow percolation rates from 0.2 to 0.6 inches per hour.

To reduce the peak developed conditions discharge from the site to the estimated pre-developed conditions, BSEP designed a retention basin to collect runoff generated from 374 acres of the entire 2,012 acre project site. Retention volume calculations were performed with HydroCAD version 8.50. The retention pond outfall structure (a rocked weir) was sized using the SCS Synthetic Unit Hydrograph method, Technical Release 20. The retention basin is designed to attenuate runoff from three design cells to account for undetained portions of the site. Project areas not tributary to the detention pond would outfall directly into the proposed diversion channel. **Soil & Water Table C1** provides a summary of results for the site discharge from BSEP's CDS.

Soil & Water Table C1
Summary of Peak Flows (cfs) at Detention Pond Outfall to Pine Tree Creek

Storm Duration	Pre-Development		Post-Development	
	10-year	100-year	10-year	100-year
24-Hour	48.6	175.8	48.5	175.5

BSEP OFFSITE HYDROLOGY

To estimate the design flow for the Pine Tree Creek diversion channel, BSEP plotted drainage area versus peak flow estimates from the 1995 FEMA Flood Insurance Study (FEMA ,1995). BSEP interpolated from the curve to estimate the 100-year peak flow rate for an 83.2 square-mile watershed. BSEP estimates the 100-year flood discharge to be between 14,000 to 20,000 cfs for Pine Tree Creek (BS 2008a).

REGIONAL HISTORIC FLOODS / FLASH FLOODS

Staff's research on historic flood events near the BSEP acknowledge the potential for flood hazards associated with desert hydrology. Nearby areas in Kern County have suffered from numerous damaging floods. The following accounts describe several large events that were reported or recorded since 1961. (Source: NOAA, The Interior Central California Climate Calendar, http://www.wrh.noaa.gov/hnx/ WXCALENDER.pdf and FEMA 2008). These flood events are important to include in this analysis because they provide a realistic understanding of the damaging potential for flash flooding in the region and where the applicant is proposing the BSEP.

August 23, 1961 - Flooding resulting from a thunderstorm covered roads with water and mud, trapping passengers in at least 20 cars in the Mojave area. Railroad tracks were blocked with debris for up to 18 hours.

August 17, 1983: Portions of California City were flooded after heavy rain fell in the Tehachapi Mountains and caused Cache Creek to swell. Water was the height of car windows and some houses flooded.

In 1984, there was a significant debris/mud flow from Short Canyon, which deposited sediment up to eight feet deep on properties within the subdivision in the immediate vicinity of Short Canyon.

September 5, 1991: Near Inyokern, CA, heavy rain fell causing water and mud to cover Highways 178, 395 and SR-14.

September 5, 1997 - An evening thunderstorm unleashed heavy rain in the El Paso Mountains. The thunderstorm moved from southwest to northeast up the El Paso Mountains. Reports indicated that 4.5 inches of rain fell from this storm in a little over an hour's time. The resulting flash flood through Red Rock Canyon State Park brought 28,000 cfs down through the park, across SR-14 and the Redrock-Randsburg Road. Reports indicated that a 12-foot wall of water swept over Highway 14 and subsequently over Redrock-Randsburg Road. The flooding stranded one hundred motorists and swept four cars into the water.

July 23, 2005 - Monsoonal moisture swept northwestward into the south half of California early in the morning and lingered through the next day. The deserts and mountain areas received locally heavy rain from thundershowers that resulted in numerous areas of desert stream flows. Radar estimates indicated 1-hour precipitation amounts of 2-3 inches and storm totals in excess of 4 inches. Flooding was reported along Highway 14 near Redrock-Randsburg Road.

August 15, 2005 - Thunderstorms unleashed heavy rain in California City during the evening hours resulting in flash flooding. The California City Fire Department recorded 5 inches of rain in just an hour. Portions of Highway 14 and Highway 58 flooded.

STAFF'S HYDROLOGIC ANALYSES

Staff conducted hydrologic analyses to assess the reasonableness of the applicant's peak flood flow estimate. The results of the analyses below are compared to the results from the CDS. Staff used the following hydrologic methods to analyze the Pine Tree Creek Watershed hydrology:

- Bulletin 17B, Guidelines for Determining Flood Flow Frequency, to determine peak flow data at the following gauging stations: Pine Tree Canyon; Cottonwood Creek; and Cache Creek
- Developed Regional Regression based on FEMA FIS Data
- California Regional Regression - South Lahontan-Colorado Desert Region
- Hybrid regional regression equations
- USGS regional regression equations (WSP 2433)

Staff did not prepare a rainfall-runoff model for the Pine Tree Creek watershed to assess peak flood flows at the site. Staff recommends that if the applicant were considering a rainfall runoff model, the model would be selected from the list of FEMA's "Numerical Models Meeting the Minimum Requirements for the NFIP".

Flood Flow Frequency

Staff performed statistical flood-frequency analysis using the Bulletin 17B, "Guidelines for Determining Flood Flow Frequency" (Interagency Advisory Committee on Water Data, 1982) to perform a flood-frequency analysis. Staff obtained data from Water Supply Paper (WSP) 2433 – Methods for Estimating Magnitude and Frequency of Floods in the Southwestern United States (USGS, 1997a). Pine Tree Canyon stream gage data from 1958 through 1976 was used for the analysis. **Soil & Water Table C2** presents data collected by the USGS. The highest measured flow was approximately 30,000 cfs in 1961 although the data source noted a footnote for this event. Unfortunately, staff could not locate the actual footnote. The 1961 data point was omitted from the final analyses because staff could find no other historic record of the extreme rainfall event and determined the data may be inaccurate. Also staff flood-frequency analysis with the data point showed extreme values for the 1% annual chance flood (base flood).

Soil & Water Table C2
Annual Peak Flowrate measured from the Pine Tree Canyon Gauge

Year	Annual Peak Flow (cfs)		Year	Annual Peak Flow (cfs)
1959	7.6		1969	76
1960	6.9		1970	0
1961	30,000		1971	0
1962	103		1972	330
1963	1,220		1973	77
1964	5		1974	0
1965	10		1975	4,900
1966	660		1976	5.3
1967	60		1977	130
1968	0		1978	7,700

Pine Tree Canyon is a sub-watershed having much different characteristics from the remaining Pine Tree Creek watershed area. The canyon also represents less than half of the watershed area but has the greatest potential to influence peak flow rates to the BSEP site. Staff concludes that a direct area transformation of the gauge data would not be appropriate for this assessment.

Using standard statistical methods, Confidence Intervals (C.I.) were determined at one standard deviation, or 68% C.I. to identify the upper and lower limits of the standard error for the base flood flow derived from the flood-frequency analysis. The proposed base flood discharges from the BSEP assessment are considered reasonable if they are generally within one standard error (68-percent confidence intervals) (FEMA, 2008).

Regression Analyses

Soil & Water Table-C3 below presents the results of several hydrologic studies conducted for watersheds having similar climatic characteristics as Pine Tree Creek. Each watershed discharge is plotted with its tributary area on the log-log scale plot. The following table shows which watersheds are plotted on **Soil & Water Figure-C1**.

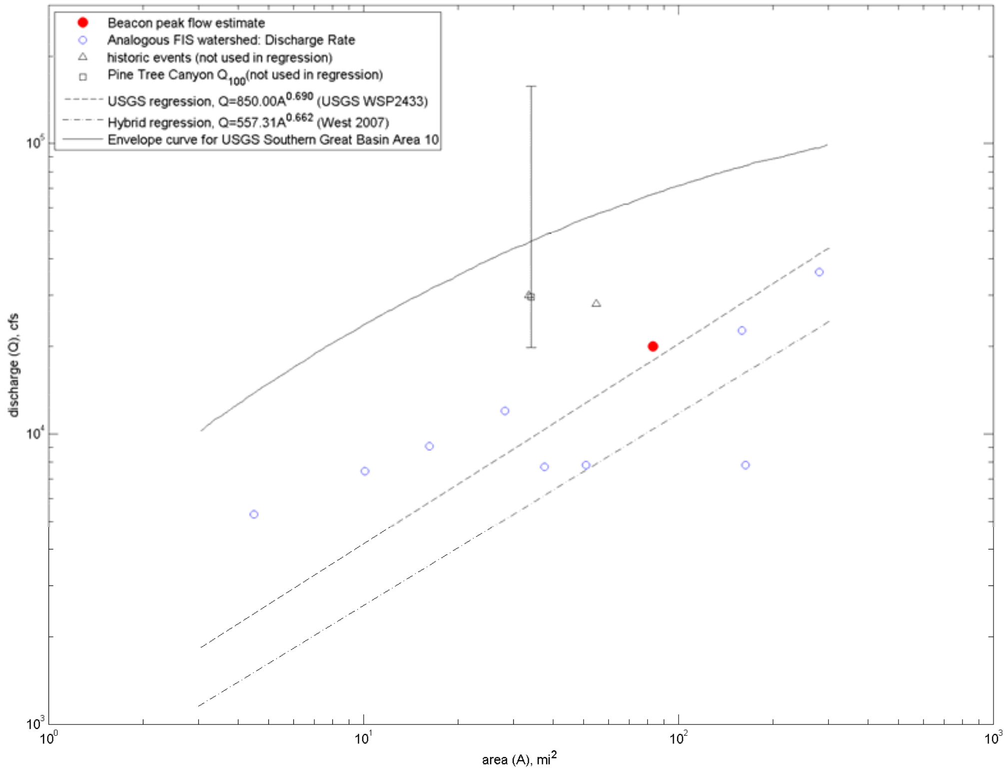
Soil & Water Table C3
100-year Peak Flowrate from the effective FEMA FIS

Watershed	Location	Tributary Area	Annual 1% chance Peak Flow (cfs)
Blackburn Creek	downstream of Tehachapi Blvd	28.2	12,030
Blackburn Creek	at Tehachapi Bldg & Dennison Rd	10.1	7,450
Blackburn Creek	at Western Corporate Limits	16.2	9,090
Blackburn Creek	Near Highline Road	4.5	5,290
Cache Creek	at Downstream Limit of Study	163.4	7,800
Jawbone Canyon Wash	at Munsey Road	280.4	36,000
Cottonwood Creek	at mouth	51.0	7,800
Erkskine Creek	At State Highway 179	37.7	7,700
Kelso Creek	At State Highway 178	159.5	2,2700

Discharge-frequency values for Kelso Creek and Erskine Creek were determined by FEMA study contractors using NRCS Technical Release No. 20 (TR-20). This rainfall-runoff model is consistent with the BSEP's initial onsite hydrologic analyses. The model considers factors such as precipitation duration-frequency data, hydrologic soils groups and land use, time of concentration, and storm type. The FEMA study contractor for Kelso and Erskine Creeks compared results from the TR-20 computer model with the results of log-Pearson Type III analyses of nearby gauging station data (FEMA 2008). The results of these two rainfall runoff models produced a base flood flow within the range of the regional regression equations described below.

The authors of the California state-wide rural regression equations, Waananen and Crippen, mention that in the Lahontan region, the equations are defined for watersheds having a maximum drainage area limit of 25 sq. miles. Because the drainage area of the Pine Tree Creek watershed is 83.2 sq. miles, the California regression equations were not used for estimating peak discharges. The authors also describe the regression equations standard error of estimate has a range of 60% to more than 100% (Waananen and Crippen, 1977).

Soil & Water Figure-C1
Hydrologic Assessment of Peak Flood Flows



Hybrid Regional Regression Equations

The California Department of Transportation, Division of Research and Innovation published the “Improved Highway Design Methods for Desert Storms” in August 2007 (West, 2007). This report was recommended to staff by Andrew Brandt, an engineer with Caltrans, District 9 (Brandt, Pers Comm, January 21, 2009). Using the following regression equation from the West study, the Q100 is 10,400 cfs.

$$Q = 557.31 * A^{0.662}$$

This regression equation is applicable for sites with a drainage area between 0.01 and 3090 square miles, with a mean annual precipitation of less than 15 inches and a mean basin elevation of less than 4500 ft. This regression equation is plotted on **Soil & Water Figure-C1** above.

USGS Regional Regression Equations

Water Supply Paper 2433 (WSP2433), Methods for Estimating Magnitude of Frequency of Floods in the Southern United States (USGS, 1997), identifies the BSEP site as being located in the USGS Southern Great Basin Area 10. Staff tested the USGS regional regression methods for the USGS Southern Great Basin. This method is applicable for drainage areas less than 200 square miles and below 8000 feet in elevation. The USGS regression equation for Q100 is shown above and plotted in **Soil & Water Figure-C1.**

$$Q = 850.0 * A^{0.690}$$

The resulting USGS regression analysis peak flow for the site is 17,960 cfs. The envelope curve shown in **Soil & Water Figure-C1** is reproduced from the USGS WSP2433, represents the maximum flow potential for a given area.

The Pine Tree Creek watershed is approximately 83.2 square-miles at the BSEP site. A range of peak flood predictions for the Base Flood Flow or Capitol Storm Design Discharge (CSDD) can be approximated from **Soil & Water Figure-C1**.

SEDIMENT / BULKING FACTORS

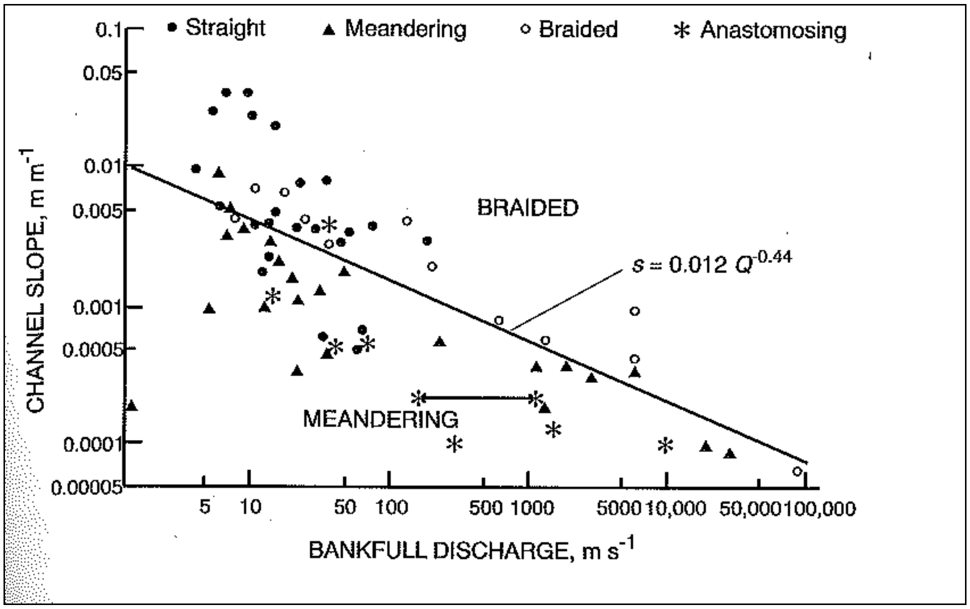
BSEP did not provide sufficient information for staff to assess the potential for significant debris laden flows and their impacts. Sediment has a high potential for contributing to the volume of flow being transported during a flood. Kern County currently does not require increasing the volume of water discharge to account for high concentrations of sediment on the flow (Aaron Leicht, pers comm., January 6, 2009). This method is generally applied to the peak design flow to obtain a total (bulked) peak flow. Typical bulking factors are 1.11 – 1.25 for normal stream flow, 1.25 – 1.67 for hyperconcentrated flow, and up to 2.0 for debris (Bradley, 1986). Caltrans recommends selection of a larger bulking factor when the flow is confined to a single, well-defined channel (Caltrans 2006), such as the proposed diversion channel.

Determining the appropriate bulking factor would require a significant understanding of the watershed and its ability to produce debris flow (West, 2007). Staff recommends that the applicant consider applying a bulking factor, consistent for use on alluvial fans, to the Safety Factor as part of their hydrologic analyses. Staff is requesting that the project owner assess the potential for sediment debris flows and adjust the peak design flow. This request would help staff identify the potential significance of sediment and its potential to affect the mitigation and carrying capacity of the diversion channel.

GEOMORPHIC ASSESSMENT

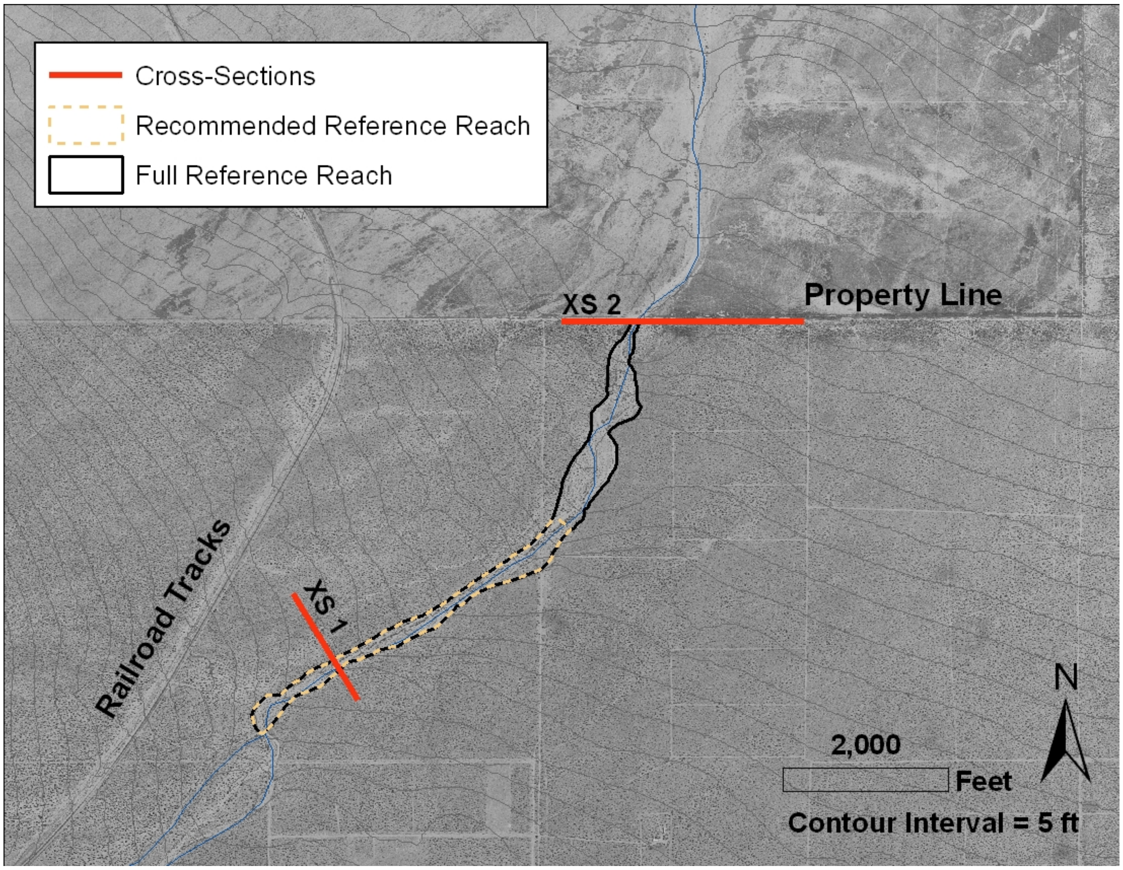
Staff conducted a desktop geomorphic assessment of Pine Tree Creek to develop an understanding of the current morphological conditions of the channel in order to assess the potential impacts from the project. Staff initially compared the proposed diversion channel slopes to the work conducted by Leopold and Wolman (1957), as shown in **Soil & Water Figure-C2**, to establish its threshold between meandering and braided channel forms, based on a bankfull discharge and channel slope relationship. The longitudinal slopes of the diversion channel range from 0.005 to 0.0138 feet/feet (or mm^{-1}). Anastomosing reaches, which fall below the braided/meandering threshold are typically low gradient streams with banks composed of cohesive silts and clays.

Soil & Water Figure-C2
Distinction between braided and meandering channels on the basis of a slope-discharge relationship (Knighton, 1998)



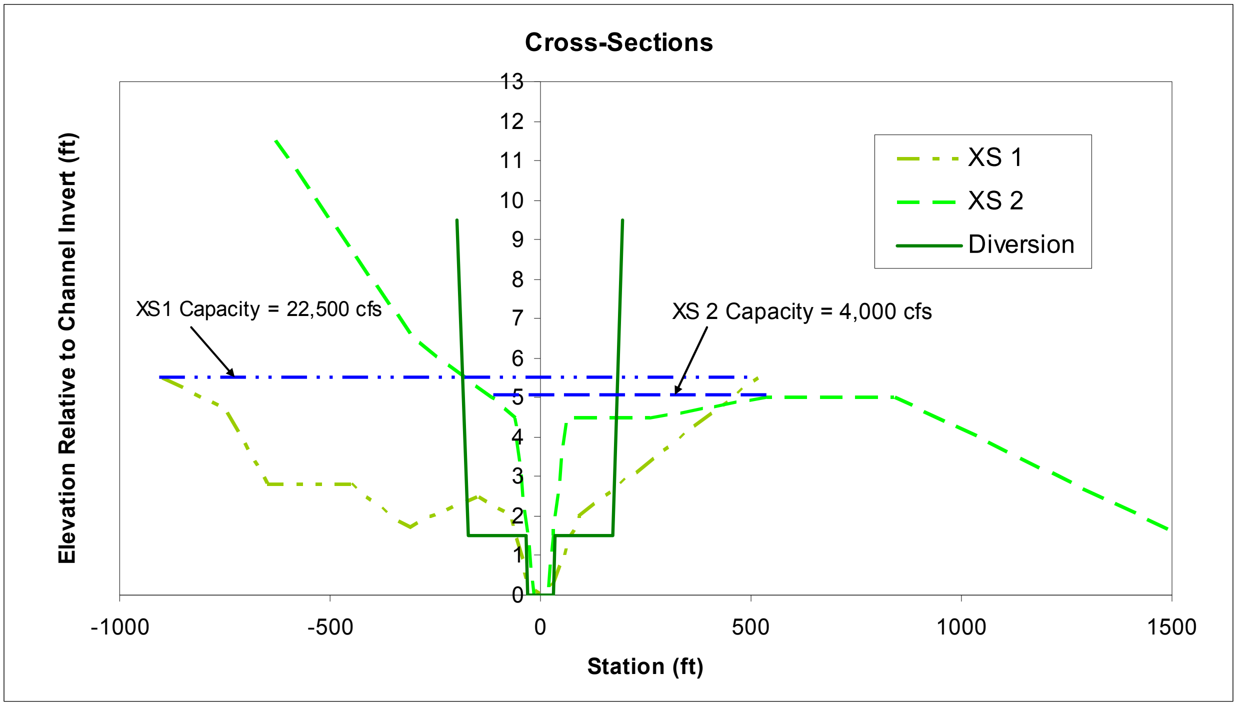
Staff examined watersheds in the region to locate a likely candidate for a “reference reach”. Due to past agricultural activities on the property, staff considered it likely that the natural morphology of Pine Tree Creek has been altered, affecting its geomorphic response, and removing it as a potential reference reach for the diversion channel. Immediately upstream of the property line is a braided reach, with a slope of 0.01 feet/feet, which provides a solid example of the desired channel form and size. This reference reach is a high gradient reach (1.0%) with bed and banks that appear to be composed of coarse sand (For comparison, the BSEP channel is currently designed with a 1.3% slope). This reference reach is delineated in **Soil & Water Figure-C3** with a solid black line. Due to the potential influence of small input channels, staff recommends that a portion of the reference reach be omitted. Staff’s recommended reference reach is delineated in **Soil & Water Figure-C3** by the dashed tan line, and begins ~2,500 ft upstream of the property line and ends ~6,500 ft upstream of the property line. For the recommended reference reach, the average width of the active channel here is approximately 185 ft, with a maximum width of 300 ft and a minimum width of 112 ft.

Soil & Water Figure-C3
Plan view of Staff's reference reach
Locations of Cross-Sections 1 and 2



Cross section 1 (XS 1), was cut from the recommended reference reach shown on **Soil & Water Figure-C3**. The main active channel (or low flow channel) for XS 1 has an approximate capacity of 877 cfs, which matches the region's Hybrid Regional Regression results (West, 2007) for the 5-year event. A second cross section was located on the southern property line, XS 2, to examine the channel capacity at property line and for staff to understand the change in cross sectional area between the natural channel and the diversion channel. According to staff's estimates, the approximate capacity of the channel at the property line is approximately 4,000 cfs. Flows greater than the channel capacity would sheet flow out of bank to the east. The overbank flow would likely continue to flow overland toward the proposed diversion channel but would not enter the channel at point of diversion where BSEP has planned to armor the channel. **Soil & Water Figure-C4** illustrates the reference reach (XS 1) and its capacity, the channel at the property line (XS 2) and its capacity and the diversion channel.

Soil & Water Figure-C4
Cross section comparison
Peak flow capacity estimated



The proposed diversion channel as designed by BSEP would have some degree of natural geomorphic function, including a limited ability to braid, meander and laterally migrate. Staff has assessed the potential for the proposed diversion channel to migrate laterally and have considered the potential for the channel to downcut. Staff has determined that for the protection against the possibility that the channel would migrate towards and erode a section of the channel bank, bank toes would require adequate stabilization. Staff also anticipates that the channel, as designed, is not adequately stable for the design flood.

Based on the work performed by Leopold & Wolman, shown on **Soil & Water Figure-C2**, staff is assuming the slope-discharge threshold applies to the diversion channel as proposed. The proposed diversion channel is a high gradient channel with non-cohesive sediment. Staff expects a braided channel to form at the base of the channel.

Staff has concluded that the low flow channel would potentially braid into a channel that would migrate along the base of the diversion channel. Based on staff's review, BSEP has not proposed adequate protection of the entire channel. Staff recommends continuous toe protection for the diversion channel to account for lateral movement of the low flow channel. Staff recommends the applicant develop design criteria for the channel suitable for earthen channel design to avoid potentially significant impacts related to flooding. Staff is requesting an **Engineering Soils Report** to provide a sufficient understanding of the soil characteristics in the channel so that the appropriate hydraulic criteria can be developed for the channel. Staff also recommends that BSEP provide mitigation measures such as bank protection or grade control when the design criteria are exceeded. Below, Staff recommends a procedure for selecting bank treatments that would minimize potential impacts to the rerouted wash.

Staff anticipates overbank flooding would leave the channel along the right bank, looking downstream, and sheet flow toward the northeast. The depth and extent of this shallow flooding has not been determined by staff. However, it is predicted that the direction of flow would not converge at the point of entry to the diversion channel as proposed by the applicant. Staff further concludes that the channel along the southern property boundary downstream of the point of diversion would experience sheet flow entering into the channel.

Staff recommends that the point of diversion, transition and bend be modeled with appropriate hydraulic software capable of determining the appropriate losses associated with this hydraulic constraint. The final design of the transition needs to be included as part of the CLOMR submittal to FEMA to demonstrate the stability of the channel under base flood conditions. Other design elements and channel protection measures also need to be described, adequately designed, and submitted to Kern County for approval. Structural elements of the channel also need to meet the provisions of the LRWQCB and the CDFG Stream Alteration Agreement. The ultimate design of the diversion channel must take into account the existing flood hazard upstream of the site and recommendations from the County.

Staff finds that active alluvial fan flooding is characterized by flow path uncertainty, abrupt deposition, and ensuing erosion of the sediment as the channel loses its capacity to carry material eroded from steeper, entrenched Pine Tree Canyon. The high level of uncertainty in hydrology, sediment, deposition, scour, and flow path ultimately results in uncertainty in defining the hazard associated with flooding. Staff is recommending that the BSEP assess the sediment transport capacity of the diversion channel. Staff recommends that a range of flows be analyzed for the diversion channel to evaluate the potential for events larger than the one percent chance flood per FEMA's Guidelines for Determining Flood Hazards on Alluvial Fans. Staff recommends that the BSEP conduct an assessment of Pine Tree Creek at it travels over the alluvial fan to identify potential variations to flow paths. Staff is requesting a **Geomorphic Study and Engineering Soils Report** to be provided for review of the diversion channel design.

The requirements of the CLOMR process require that the revised 100-year floodplain would be delineated in accordance with 44 CFR 65.12. FEMA's Guidelines and Specifications for Flood Mapping Partners must be used for guidance in determining the technical requirements for submitting an application for a CLOMR/LOMR.

HYDRAULICS

BSEP HYDRAULIC ANALYSES

To evaluate the flood potential of the proposed diversion channel, staff reviewed BSEP's hydraulic analysis used in the channel design. The proposed diversion channel would divert Pine Tree Creek flows at the location where the existing channel crosses the southern property boundary. The diversion channel is planned as a trapezoidal channel having 3:1 side slopes, with a minimum bottom width of 345 feet to a maximum of about 2,900 feet at the end of the transition. The peak design flow for the diversion channel was estimated by BSEP at 20,000 cfs.

At the diversion, the design discharge would likely experience super-elevated hydraulic conditions along the outside of the constructed channel bend. BSEP has recommended a 5.0 foot high berm along the left bank (looking downstream) to maintain conveyance in the diversion and protect the solar facility from inundation from the design flood. The centerline radius for this bend was estimated to be 600 feet. BSEP refers to this bend as “Turn #1 – 65 degree turn”. The channel banks at this location range from 2:1 to 3:1. The channel slope through the transition is designed at 1.3%.

The diversion channel would make a 90 degree bend to the north before reaching the eastern property boundary. The channel slope would change from 0.5% to 1.4% near the 90 degree bend. Roughly one mile north of the 90 degree bend, the channel widens through a transition and its alignment would be redirected toward the northeast corner of the property.

The roughness for the channel was assigned 0.035 which was to allow for a stone covered channel bottom and weed covered banks. Exposed rock in the bed of the channel is proposed at the point of diversion from the natural channel and at the 90 degree bend to the north. The channel is designed with a minimum depth of eight feet, which includes a minimum of one foot of freeboard. The diversion channel segment would be approximately 14,000 feet long. The channel would be revegetated with native vegetation following excavation.

The diversion channel is designed with a transition near the mouth of the channel that widens to nearly 10 times the top width of the typical channel cross section. The intent of this design is to reduce flow depths and spread the channel flow onto a wide area. A concrete sill, or flow spreading structure, is proposed to provide dispersion of peak flood flows. The concrete sill would be keyed in to the proposed channel to a depth of 4 feet below the channel invert.

The hydraulic calculations by BSEP indicated that the hydraulic depth of flow is between 3.5 to about 6.0 feet and the velocity would be between 8 to 13 feet per second (fps). Froude numbers were approaching 1.0 in the steepest reach of the channel.

STAFF’S HYDRAULIC ANALYSES

To evaluate various parameters used in BSEP’s analysis, staff performed a separate model analysis. Staff’s hydraulic model was setup using similar channel characteristics used by BSEP. The model began where the proposed diversion channel is proposed to widen from its 345 foot base. The model extends 7,600 feet upstream to the point of diversion. The downstream boundary condition was set to normal depth and assigned a slope of 1.38% as proposed by BSEP.

Three primary reaches of the diversion channel were established: 1) a straight channel at 1.38% slope; 2) a 90 degree bend at 1.13% slope; and 3) a straight reach at 0.5%

slope. Channel banks were maintained at 3:1. Manning's roughness values were similar to the BSEP proposed channel estimates. Bend losses (k=0.08) were added at the 90 degree bend.

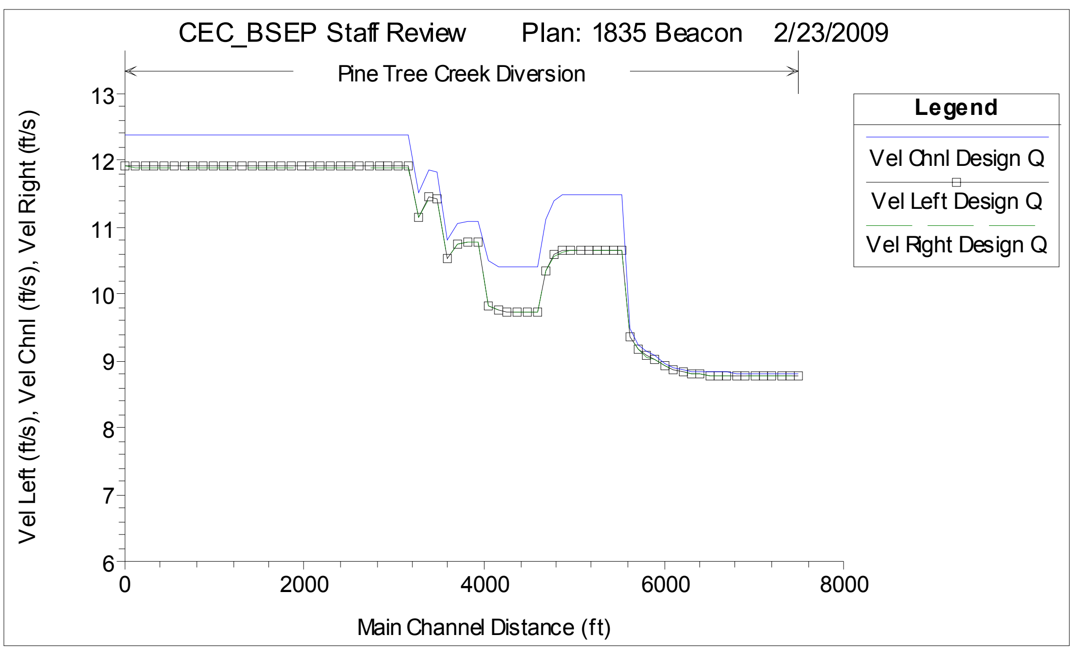
Flow conditions were established for the peak flows determined by Staff in the PSA. **Soil & Water Table C4** presents the multiple profile flow values. The Q5 flow was used to assess the bankfull channel conditions. The Design Flow of 20,000 cfs was used to evaluate the channel design.

Soil & Water Table C4
Summary of Peak Flows (CFS)

	Q5	Hybrid Regression	Statistical Regression	USGS Regression	Design Flow	Upper limit
Flowrate	877	10,404	13,400	17,960	20,000	22,000

The results of staff's analyses are shown graphically in the following figures. **Soil & Water Figure-C5** presents the results of the velocity for flow in the main channel (low flow) and flow in the overbank or floodplain areas. The low flow channel dimensions, from the BSEP design, define the channel width. The resulting velocities vary throughout the study reach. Velocities are lower at the upper end of the channel where the slope is less steep at 0.5%. Velocities throughout the study reach are well above typical design velocities for natural earthen channels of 5 to 6 fps.

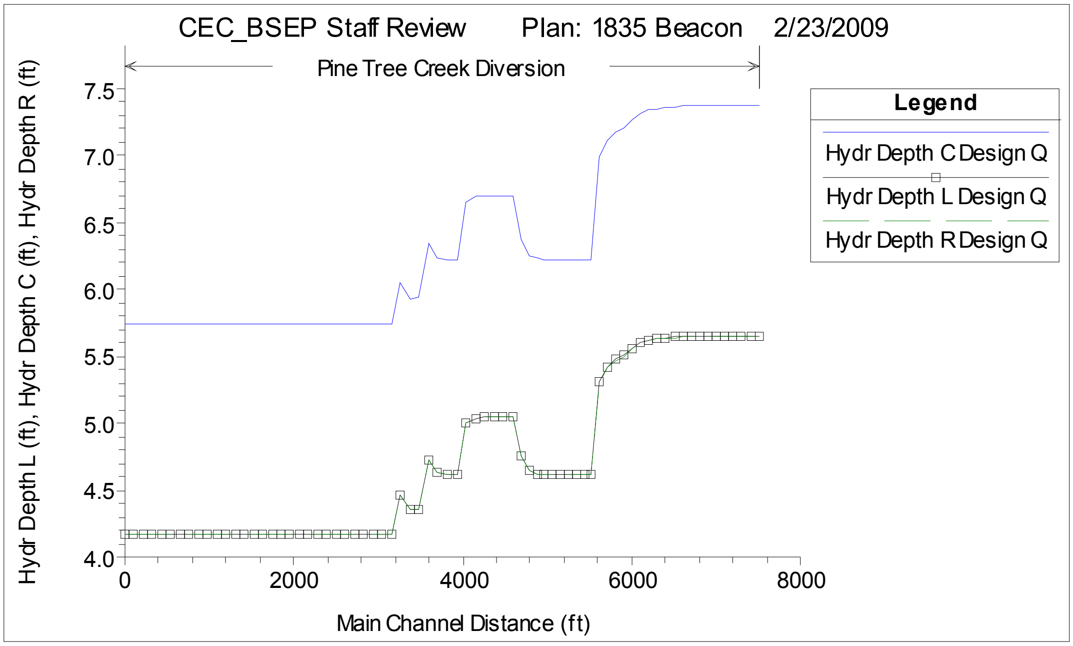
Soil & Water Figure-C5
Staff Hydraulic Model – Velocity Profile



Soil & Water Figure-C6 shows the results of the hydraulic depth for flow in the main channel and depths in the right and left overbank areas. Greater depths of flow require greater excavation depth or may require levees to contain the design flood.

Soil & Water Figure-C6

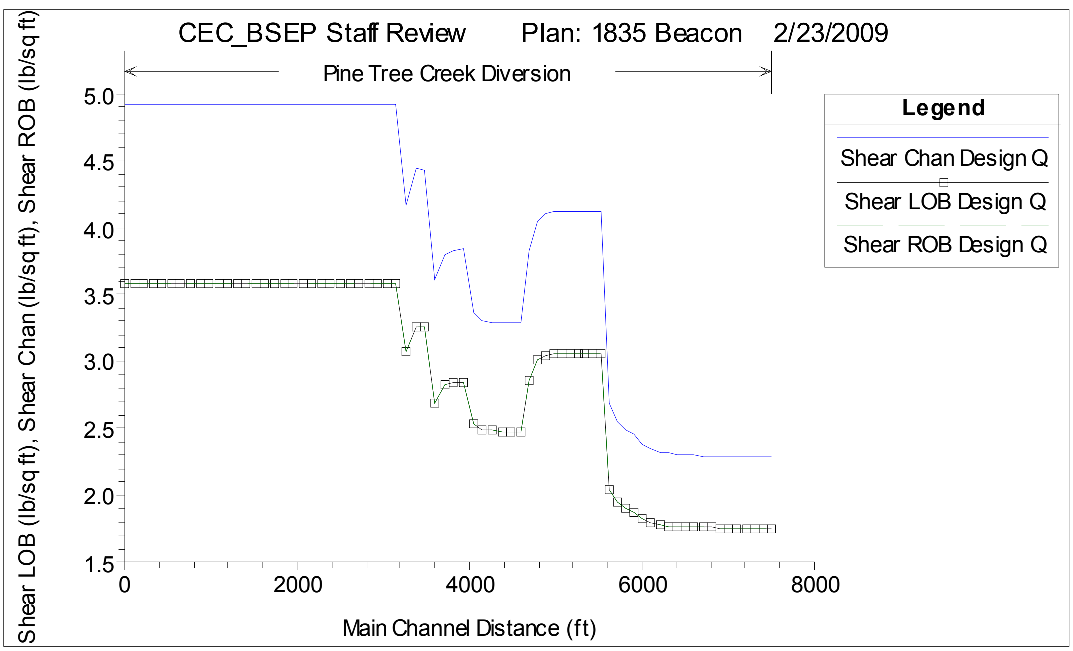
Staff Hydraulic Model – Hydraulic Depth Profile



Soil & Water Figure-C7 shows the results of the shear along the channel and overbanks of the study reach. These shear stress results are particularly high in the steep reach of the channel. High shear typically requires bank treatments to protect the banks from erosion and failure. Staff examined several bank and channel treatments in the PSA and have specified typical ranges of allowable shear stress for each. To reduce the need for structural bank treatments, staff recommends that the shear stress in the study reach be reduced.

Soil & Water Figure-C7

Staff Hydraulic Model – Shear Stress Profile



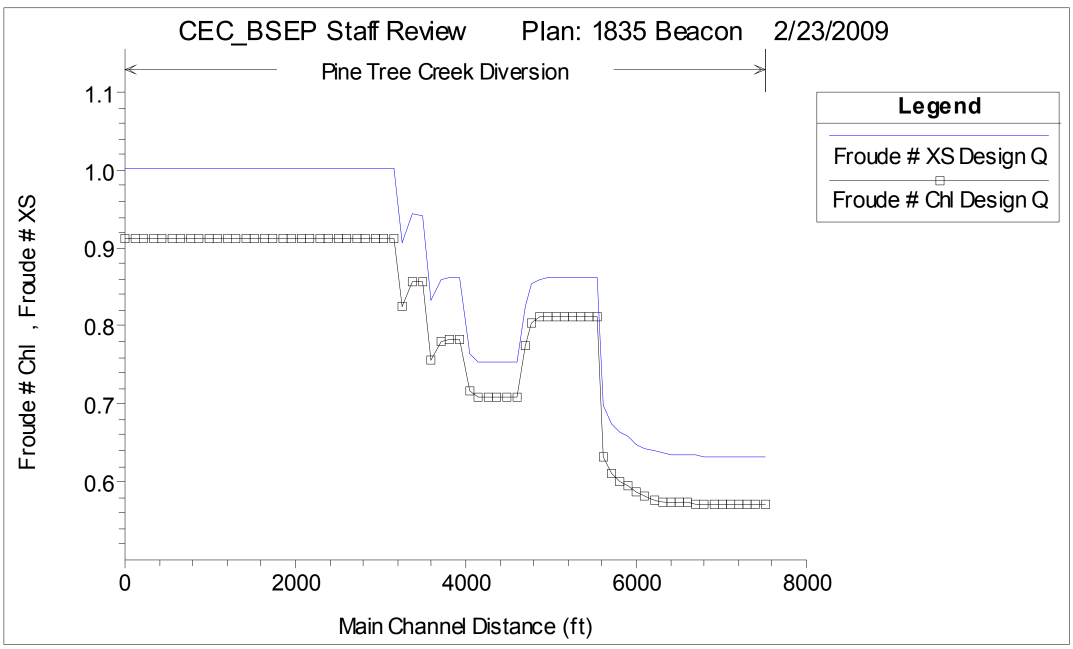
Soil & Water Figure-C8 graphically depicts predictions for the Froude Number for the channel. This figure provides a preliminary check for the proper flow regime. It is anticipated that the final channel design should result in Froude Numbers less than 0.80 for natural earthen channels. The estimated value for the Froude Number in the main channel and the overbank areas is approaching 1.0 in the steeper reaches of the channel. This means the flow is approaching critical depth and may possibly transition into supercritical flow which is not typical for a natural channel. The following equation is used to determine the Froude Number:

$$\text{Froude Number} = V / (g * Y)^{(1/2)}$$

Where g is equal to 32.2 ft/s^2, Y is the depth of flow in feet, and the velocity (V) is in feet per second (fps).

Soil & Water Figure-C8

Staff Hydraulic Model – Froude Number Profile



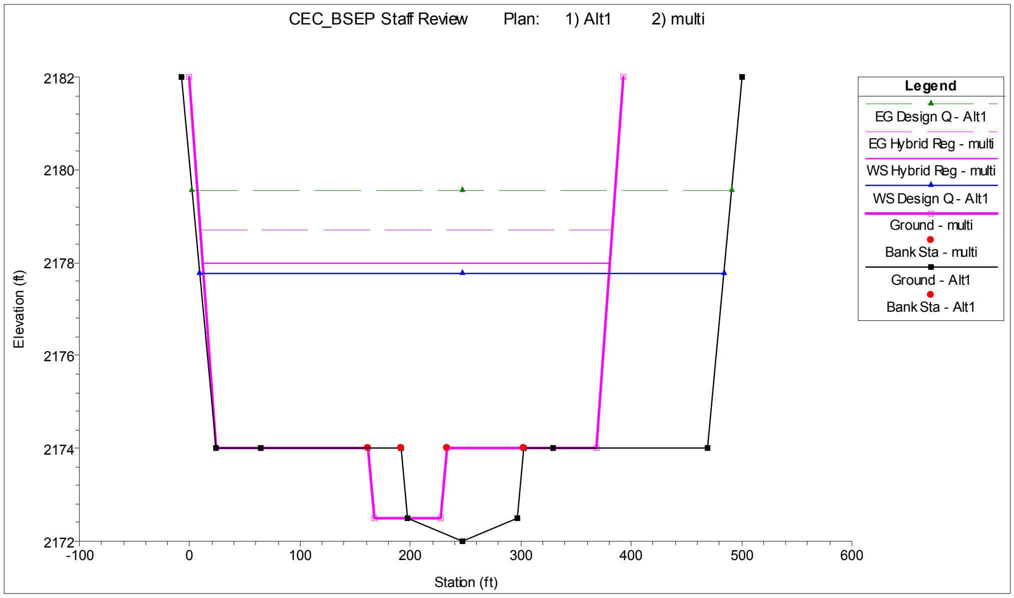
STAFF'S ALTERNATIVE HYDRAULIC MODEL

Staff setup an alternative model to examine hydraulic conditions for a similar channel designed with a continuous slope. The continuous slope (1.04%) alternative would assess the potential for the channel to meet specific hydraulic characteristics. Side slopes were changed to 4:1 to comply with the Kern County design guidelines. Roughness values were modified to a composite channel roughness of 0.038. The extent of the model is the same as the previous staff model.

Soil & Water Figure-C9 provides a comparison of two cross sections located at the upper end of the study reach. The alternative model cross section width was increased a nominal 100 feet and the low flow channel was slightly deepened and widened.

Soil & Water Figure-C9

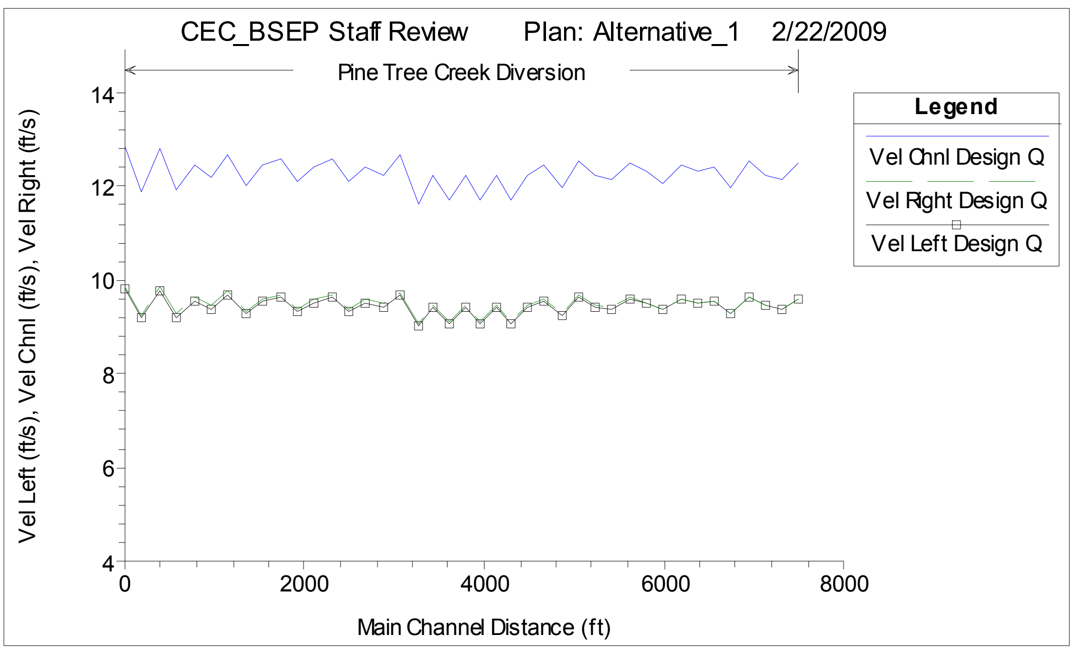
Staff Hydraulic Model and Alternative 1 – cross section comparison



The velocity results of Staff's alternative analyses are shown graphically in **Soil & Water Figure-C10**. Results from this analyses are more uniform owing to the continuous cross sectional shape and channel slope. Velocities remain well above typical design velocities for natural earthen channels of 5 to 6 fps.

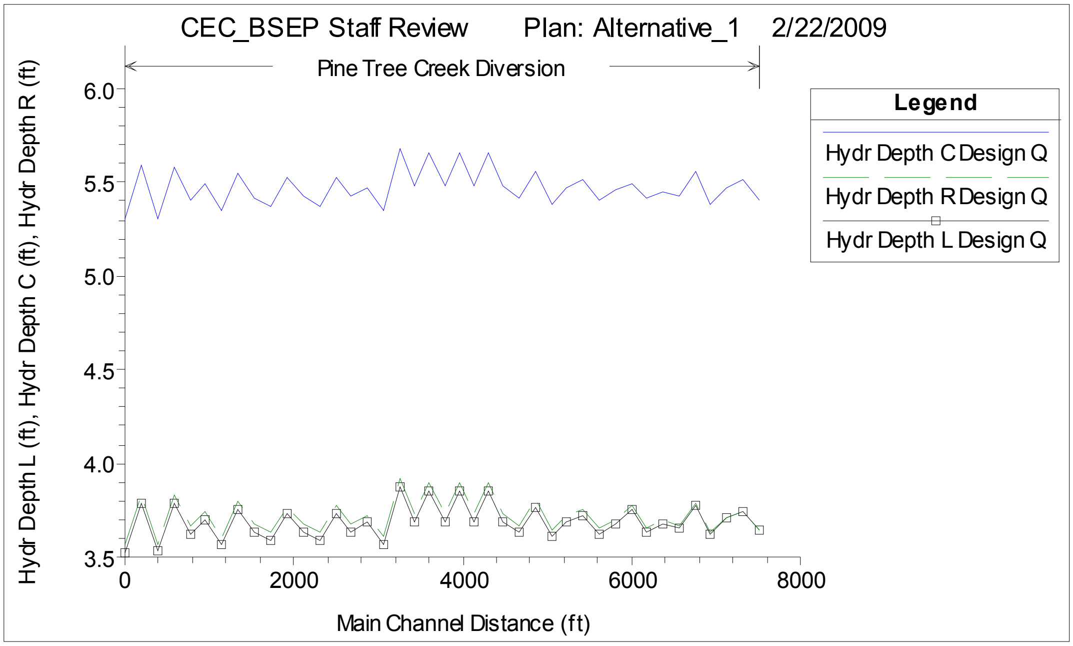
Soil & Water Figure-C10

Staff Alternative 1 – Velocity Profile



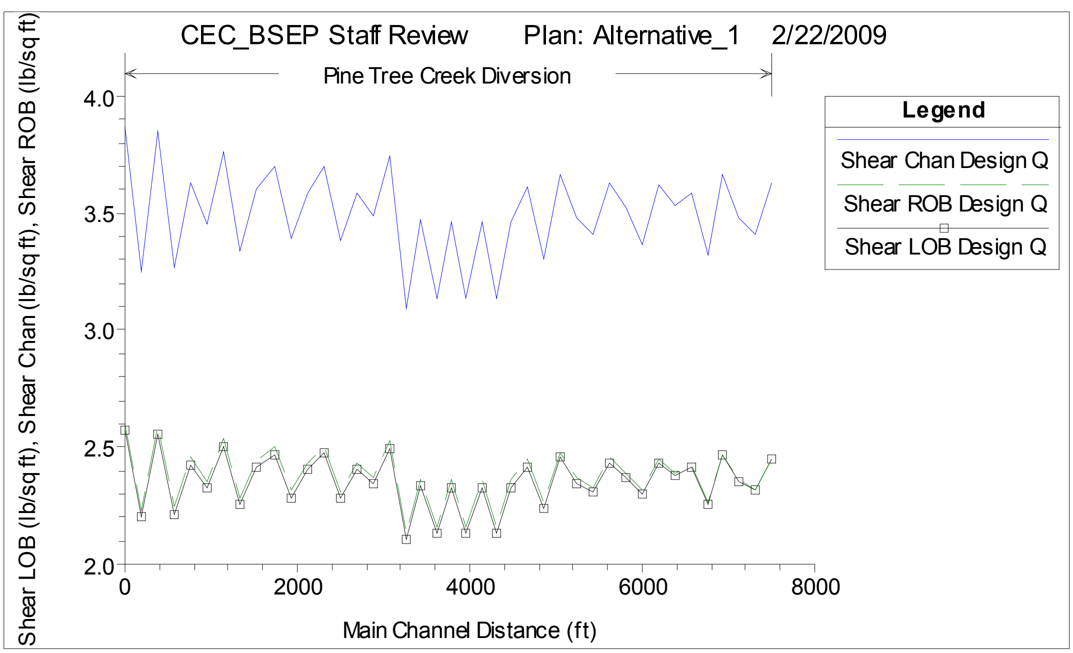
The hydraulic depth results are shown in **Soil & Water Figure-C11** below. These depths are more typical of natural channel and floodplain characteristics. The widened channel provides a more significant flow path which results in slightly lower water levels.

Soil & Water Figure-C11
Staff Alternative 1 – Hydraulic Depth Profile



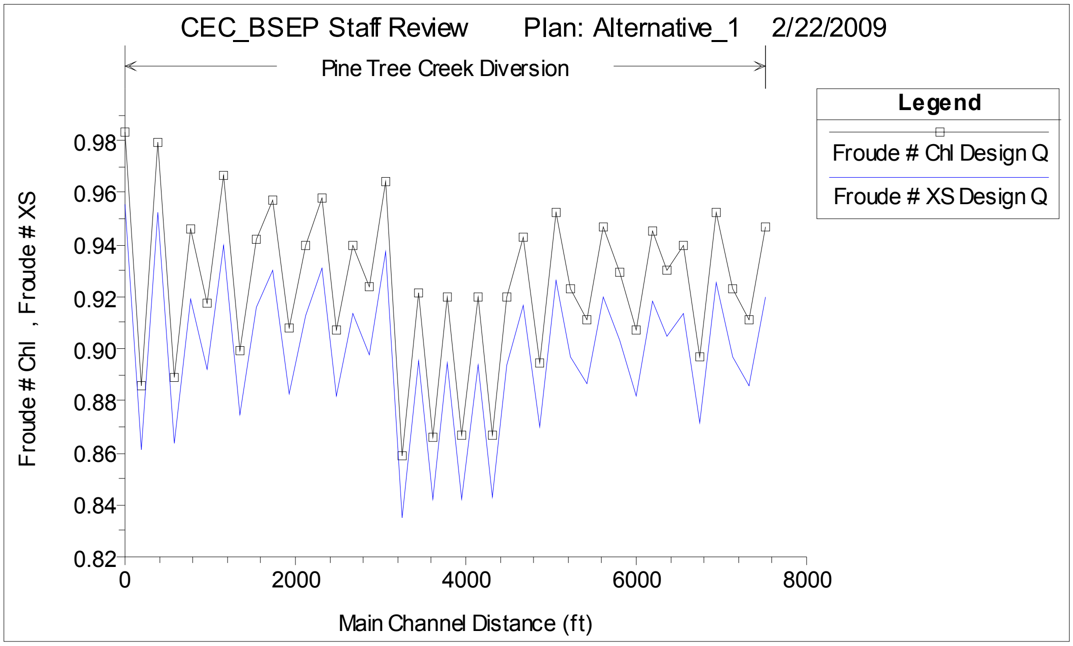
Soil & Water Figure-C12 presents the shear stress results for the alternative study reach. As anticipated the shear stress was more consistent throughout the channel when the slope was maintained as a constant.

Soil & Water Figure-C12
Staff Alternative 1 – Shear Stress Profile



Finally, the Froude Numbers are presented in **Soil & Water Figure-C13** below. These Froude Numbers remain above the 0.80 target signally a need to reduce the velocity.

Soil & Water Figure-C13
Staff Alternative 1 – Froude Number Profile



BANK PROTECTION

BSEP BANK PROTECTION

BSEP has proposed various rock bank and toe protection treatments throughout the diversion channel. At the point of diversion, BSEP has proposed a rock-lined channel from the property boundary to protect the excavated channel through the transition to the proposed channel. Caltrans Light Class Rip Rap would line the channel for roughly 1,150 feet along the centerline from the southern property boundary. The rock protection would extend up to the top of the 5.0 foot berm located on the left bank of the channel. Once the channel flow has made the transition from the north flowing natural channel to the diversion channel flowing east, the rock lining ends and an earthen channel maintains a 0.5% slope.

A subsurface keyway would be constructed along the toe of slope on both the right and left overbanks of most of the channel length. The keyway rock was sized to be No 1 Backing Class (Caltrans Standard Specification, 2007) with a depth of 8 feet below the channel bank toe of slope which requires about 3.0 cubic-yards per linear foot (both sides) of channel. The keyway is discontinuous at the 90-degree bend and replaced by a riprap bank slope protection and a rock-lined low flow channel.

STAFF'S BANK PROTECTION RECOMMENDATION

The BSEP channel protection treatments proposed by the applicant does not adequately respond to LRWQCB and CDFG provisions that seek to minimize impacts to

Pine Tree Creek diversion channel. Staff has also concluded that the proposed bank treatments would not sufficiently protect the channel from the hydraulic forces anticipated from the design flow. Staff does support the use of the subsurface keyway as the primary form of bank toe protection preventing the lateral migration of the low flow channel and protecting the bank from local scour. Because the lateral movement of the channel is mostly unpredictable in the straight reaches of the channel, staff recommends applying the toe protection for the entire length of the channel.

Staff recommends that proposed bank protection (bank treatments from the toe of slope up to the height of the freeboard elevation) options be selected based on the hydraulic response of the design flow. The type of protection would be selected to sufficiently prevent erosion of the newly constructed banks or significant lateral movement into areas where infrastructure, future homes (adjacent properties), structures, or higher public use may occur. Bank protection would be designed as a permanent treatment that would protect from the maximum hydraulic design criteria established for the channel.

In an effort to respond to the provisions of the CDFG Streambed Alteration Agreement, staff provided methods for establishing bank protection selection criteria. Various options for bank protection should be evaluated based the following selection criteria:

Selection Criteria

1. Examine Maximum Potential shear stress and velocity for the following conditions: at bends; in areas of fill; at contractions and expansions; along maintenance roads; and where the proposed channel ties into the existing natural channel

2. Use results from proposed conditions hydraulic analysis to determine channel velocity, left and right overbank velocity and shear stress. Summary tables and graphs provide a good overview of the channel response for velocities and shear stress.

3. If the criteria has been exceeded, select an appropriate bank protection option from that meets the shear stress and velocity criteria or re-evaluate the channel design.

4. Use appropriate methods to estimate potential scour depth and height of bank protection - design bank protection to meet the Kern County Division Four, Standards for Drainage.

Bank Protection Options

Staff has identified a variety of bank protection methods considered appropriate for different applications. Where the shear stresses and velocities are low enough, staff has emphasized use of bioengineering solutions over traditional engineering stabilization methods (e.g. rock or concrete armoring) to provide long-term resilience and habitat enhancement. Bioengineering solutions achieve stability by incorporating live vegetation with more structural materials (e.g. rock, deep rooted vegetation). Over time, the vegetation establishment strengthens the bank at the surface (by increasing roughness and reducing shear stress) and subsurface (via the root matrix). Proper selection of the appropriate plant materials (e.g. shrubs) is critical for success. Biotechnical approaches require sufficient soil moisture for plant establishment and subsequent survival, which would be a limiting factor in the diversion channel. Where shear stresses and velocities are higher than those that biotechnical materials can withstand, staff has recommended approaches that rely upon hard materials for their basic mechanical resistance, but incorporate live material to enhance both strength and biological function. The four main categories for potential bank protection options are listed below, generally in order of increasing shear resistance:

- Vegetation
- Biotechnical Solutions
- Synthetic Geotextiles
- Structural Methods

The potential for lateral migration of the low flow channel is related to the vegetal shear and particle shear resisting capacity of the floodplain. The wider the floodplain the more the vegetation and earth that separates the low flow channel from the toe of slope. Staff has assumed three potential categories for the migration of the low flow channel at this time: Low, Medium and High potential.

Description of the Alternatives

Staff is recommending various permanent bank stabilization options, which would be applied on a selective basis. The bank protection options may provide longitudinal protection, have transverse construction, or be recommended as an erosion control option during re-vegetation of the channel for mitigation. A general introduction to these options follows.

Vegetated Floodplain and Vegetated Toe Protection – *This bank protection option is staff's preferred method. To be selected, specific hydraulic and bank protection selection criteria have been met. This option is only recommended by staff along corridors with a low potential for streambed migration into the channel banks. This approach is non-invasive to protect the bank using native plants and shrub species applied to the floodplain and toe of channel slope. This option is also the preferred approach by CDFG. Plants must be an approved species.*

Soil & Water Table C5
Staff's Recommended Design Criteria for Vegetated Bank Protection

Permanent Bank and Toe Protection (Longitudinal)	Min Side Slope (H:V)	Permissible Shear Stress (lbs/SF)	Permissible Velocity (fps)	Hydraulic Requirement (Moisture regime)
VEGETATION				Low
Vegetation – Short Native & Bunch Grass	4:1	0.7 – 0.95	3.0	TBD
Vegetation – Long Native Grasses	4:1	1.2 – 1.7	4.0	TBD
Vegetation - Shrubs	4:1	1.5 – 3.0	5.0 - 7.0	TBD
VEGETATION WITH REINFORCEMENT				
Turf Reinforced Matting	4:1	3.0 - 4.5	7.0	Low

Planted Riprap Toe Protection - *This protection should be used where the proposed channel has a* <u>*medium to high*</u> *potential for lateral migration into the channel banks. (This option has been proposed by the applicant for select areas of the channel.) The base or horizontal portion of the riprap is designed to be embedded to a local scour depth below the stable bed. Scour depth would be defined using acceptable Kern County methods. The top of the sloping portion is to be at or above the design flood level. Additional protection should be extended to the height of the calculated top of bank protection using Kern County methods for bank protection freeboard. Planted rock would be used, which would further protect the bank from erosion and allow riparian vegetation growth. Revegetation would mitigate impacts and provide erosion protection by reducing velocities near the banks and creating cohesive root systems between the planted riprap and below the channel bottom.* ***Soil & Water Table C6*** *below provides an example of the variation in riprap sizes associated with greater levels of permissible shear stress and velocity.*

Soil & Water Table C6
Staff's Recommended Design Criteria for Rock Bank Protection

Soil-Riprap and Plants	Max Side Slope (H:V)	Permissible Shear Stress (lbs/SF)	Permissible Velocity (fps)
Planted-Riprap 6-in D50	4:1	2.5	5 - 10
Planted-Riprap 9-in D50	4:1	3.8	7 - 11
Planted-Riprap 12-in D50	4:1	5.1	10 - 13
Planted-Riprap 18-in D50	4:1	7.6	12 - 16
Placed Rock / Boulders 24-in +	3:1*	7.6 – 10.0	15+

* would require a variance from Kern County Division Four Standards for Drainage

Synthetic Geotextiles – Synthetic geotextiles are to be considered for specific cases requiring slope stabilization. Turf Reinforced Matting is an example of a manufactured product that can be applied to the channel side slopes and vegetated for additional erosion protection. Fabrics are relatively inexpensive for certain applications as opposed to concrete and riprap and are less invasive. A wide variety of geotextiles are available to match specific needs. For instance, natural fibers such as coconut can also be woven into mats that are biodegradable but provide erosion control as the slopes vegetate. Primary permanent uses of synthetic geotextiles would be above the toe slope protection. In-channel uses or as an erosion protection for swales would be limited unless manufacturer's recommendations are exceeded.

Structural Solutions Channels where vegetation is difficult to establish and maintain as a defense may require hard armor protection. This option is also more likely for streambed channels that have a high potential for lateral migration into the channel banks.

Soil & Water Table C7
Staff's Recommended Design Criteria for Structural Bank Protection

STRUCTURAL	Max Side Slope* (H:V)	Permissible Shear Stress (lbs/SF)	Permissible Velocity (fps)	Plant Dependent
Soil Cement	0.5:1	11.0 +	15+	N/A
Cribwalls, Vegetated	0:1	12.0 +	15+	Varies - Plant Dependent
Stacked Grouted Boulders	0.5:1	12 +	15+	N/A

* would require a variance from Kern County Division Four Standards for Drainage

Transverse Bank Protection - Additional channel stabilization options would provide benefits for protecting the channel banks. Permanent transverse options such as rock vanes, bend way weirs, or J-hooks may also be considered to provide additional protection for redirecting an active low flow channel, especially at significant bands in the channel, as proposed by the applicant. Other biotechnical measures can be built into the floodplain to provide initial roughness and reduce bank shear stresses of overbank flows to prevent floodplain scouring or channel avulsion. One example treatment is a shrub or sub-shrub baffle, where species are placed and anchored perpendicular to the flow on the floodplain.

GRADE CONTROL

Staff's bank and channel stabilization recommendation is based on the establishment of stable channel slopes which would reduce velocities and thus erosion potential. Staff believes that the channel, as proposed, is too steep for the design flood of 20,000 cfs and that there is a high uncertainty in the proposed bank protection to protect the banks from erosion and failure. With the channel profile controlled, anticipated bank erosion can be mitigated and future impacts due to diverting the natural channel minimized. Staff recommends that the BSEP evaluate the need for grade control or instream structures that dissipate hydraulic forces and reduce the effective longitudinal slope of the channel.

CONCLUSIONS

The key findings and outstanding issues identified by our technical evaluation of the Special Flood Hazard Areas, Hydrology, Geomorphic Assessment, Hydraulics, Bank Protection and Grade Control are summarized below:

1. The effective FEMA DFIRM SFHA mapping for the site was determined from approximate methods and may not accurately describe the existing 100-year limits of flooding. The BSEP flood hazard assessment does not adequately address impacts upstream and downstream of the proposed diversion channel.

2. BSEP did not adequately assess all offsite drainage areas tributary to the site. The drainage area east of the Barren Ridge watershed and the area draining the Chuckwalla Mountains were not evaluated for the potential for flood flows to enter the site.

3. Historic floods near the BSEP site demonstrate the potential for extreme flooding from the Pine Tree Creek watershed.

4. The BSEP estimate for the Pine Tree Creek 100-year design flow of 20,000 cfs is reasonable. Bulking factors were not used for the 100-year design flow estimate.

5. The existing Pine Tree Creek channel upstream from the property does not have the capacity for 20,000 cfs without flowing out of bank. The flood flow would be expected to cause shallow flooding outside of the existing SFHA along the right bank toward Jawbone Creek.

6. There is an uncertainty about whether the Pine Tree Canyon alluvial fan is active or inactive. The Pine Tree Creek flow path is uncertain. The sediment transport capacity of the proposed channel is not known.

7. Staff concluded that the low flow channel of the diversion channel as proposed would become braided not anastomosing as defined proposed by BSEP.

8. The proposed diversion channel does not adequately meet the requirements of Kern County design standards.

9. The resulting design flood velocity, depth, shear, and Froude Number are high compared to the anticipated channel stability thresholds of the proposed earthen channel.

10. The diversion channel bank protection does not adequately protect the channel from the anticipated hydraulic forces, velocity and shear stress. Grade Control may be required to maintain the channel grade and improve hydraulic characteristics.

RECOMMENDATIONS

Based on the key findings and outstanding issues identified in our assessment Staff recommends that the applicant provide additional detailed analysis for staff's review. Staff requests the following engineering studies:

- Revised Conceptual Drainage Study
- Geomorphic Study
- Revised Diversion Channel Design
- Soils Engineering Report

These recommendations are consistent with the recommendations in Soil & Water Section of the PSA.

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SOIL AND WATER RESOURCES - APPENDIX D

ANALYSIS OF ALTERNATIVE WATER SUPPLY AND COOLING TECHNOLOGIES

State Water Board Resolution 75-58 addresses the use of inland waters used for power plant cooling. The resolution defines unreasonable use, and promotes the consideration of alternative power plant cooling options. Pertinent statements contained in Resolution 75-58 follow:

- The loss of inland waters through evaporation in power plant cooling facilities may be considered an unreasonable use of inland waters.
- The source of power plant cooling water should come from the following sources in this order of priority depending on site specifics such as environmental, technical and economic feasibility consideration:
    1. Wastewater being discharged to the ocean,
    2. Ocean,
    3. Brackish water from natural sources or irrigation return flow,
    4. Inland wastewaters of low TDS, and
    5. Other inland waters.
- Use of fresh power plant cooling will be approved by the Board only when it is demonstrated that the use or other water supply sources or other methods of cooling would be environmentally undesireable or economically unsound.
- Studies associated with power plants should include an analysis of the cost and water use associated with the use of alternative cooling facilities employing dry, or wet/dry modes of operation.

The following sections describe our independent analysis of alternative water supply and cooling technologies.

The examination of alternative water supplies and cooling technologies begins with a determination of whether a project will use fresh water for cooling. The IEPR itself does not define what constitutes fresh water. Resolution 75-58, upon which the IEPR water policy is based, defines fresh inland waters as "*those inland waters which are suitable for use as a source of domestic, municipal, or agricultural water supply…*" (State Water Resources Control Board Resolution 75-58, p. 3.) Thus, fresh water is not given a narrow definition but is broadly defined by how it is used, evincing an intent to be as inclusive as possible. The groundwater proposed for use by the BSEP meets the definition of fresh inland water under Resolution 75-58 because it is used for agricultural and domestic use in the area.

Another indication of the suitability of this water as a domestic source is its compliance with the Drinking Water Standards found in Title 22 of the California Code of Regulations. As discussed in the groundwater quality section of the AFC, the BSEP proposes to use groundwater that has a TDS of 470 - 550 mg/l (AFC). This TDS level is well within the secondary maximum contaminant level (MCL) for TDS in drinking water of 1000 mg/l and near the recommended limit of 500 mg/l (Cal. Code Regs., tit. 22, §§ 64431, 64449). Secondary MCLs are based on aesthetics and intended to protect odor, taste and appearance. Exceeding these secondary MCLs does not necessarily preclude the use of that water for drinking.

BSEP has proposed to use this onsite fresh groundwater for all plant needs including cooling and steam generator feed water as well as potable uses. Cooling would be provided by a mechanical draft cooling tower. Plant wastewater (from all sources) would be sent to evaporation ponds for final disposal. No backup cooling water supply is proposed by the applicant although they offer to use future tertiary treated effluent from California City if it becomes available.

The applicant estimates water use as follows:

Soil & Water Table D1
Proposed Annual Operational Water Demands

Water Use			
Water Use	Annualized Average Rate[1], gpm	Peak Rate[2], gpm	Estimated Annual Use, Acre Feet
Plant Operation	990	4,054	1,599
Potable Water	5	5	8

1. The estimated groundwater usage in gallons per minute is based on an average daily consumption.
2. The peak rate is the instantaneous maximum for summer usage.

Water uses would include cooling tower makeup, closed cooling system makeup, steam generator makeup, mirror washing, plant wash down (housekeeping and maintenance), dilution water for chemical feed systems, etc. Well water would also be used for potable uses - drinking, showers, sinks, and toilets. Well water would be stored on site in the Raw Water Tank. Most of the water would be treated using ion exchange utilizing strong acid cation (SAC) and strong base anion (SBA) and stored in the Process Water Tank. Process water would be used for cooling tower makeup. A portion of the process water would be treated further for steam generator makeup and mirror washing utilizing portable demineralizers (these are regenerated offsite and generate no wastewater).

ALTERNATIVE WATER SUPPLY

Resolution 75-58 is clearly intended to broadly protect beneficial uses of the State's water resources. In this vein, the SWRCB states that "*in considering issuance of a permit or license to appropriate water for power plant cooling, the Board will consider the reasonableness of the proposed water use when compared with other present and future needs for the water source and when viewed in the context of alternative water sources that could be used for the purpose*" (Resolution 75-58, pgs. 5 & 6). Although no appropriative right is at issue in this case, increasing groundwater demands on a fresh water supply dictate that the Energy Commission consider the reasonableness of allowing BSEP to use groundwater of a quality suitable for domestic use when a source of lower quality water (TDS in excess of 1000 mg/L) that cannot be used for domestic purposes without extensive treatment is available in the aquifer approximately 5 miles to the east of the site in the vicinity of Koehn Lake. Staff considers the higher TDS groundwater located near Koehn Lake to be a reasonable alternative to the proposed use of high quality fresh groundwater located beneath the proposed project site.

The brackish groundwater located southwest of Koehn Lake is the same water source considered for all of the alternatives (1 through 5). Each to-be-constructed well is assumed to be 500 feet deep. The pipeline diameter for Alternatives 1 and 3 is 14 inches and for Alternatives 2, 4 and 5, 12 inches. The size differences are a function of water demand for each alternative. For this analysis, the line was sized to operate 24 hours per day at half the water demand rate.

WATER TREATMENT PROCESSES

With alternative water supply sources, alternative water treatment processes must be considered. Each of the five alternatives uses a combination of water treatment processes. All of the processes shown in **Soil & Water Table D2** are well established commercial technologies.

A discussion of each water treatment process is provided below:

SAC-SBA

As mentioned above, SAC-SBA vessels contain ion exchange resin specifically designed to remove cations (positive ions) and anions (negative ions) from water. This process is the same ion exchange process proposed by BSEP and would be used in Alternatives 1, 2 and 4.

REVERSE OSMOSIS (RO)

RO is a technology that utilizes permeable membranes (under relatively high pressure) to repel salt and pass water. Most of the dissolved salts are repelled by the membrane surface (95% to 98% for most ions) allowing only water to pass through the membrane. RO must have highly filtered water with modified chemistry (usually pH adjustment) to operate successfully. In the alternatives utilizing RO, the water would be filtered by the use of microfiltration (MF). MF is also a membrane process that is commonly used with RO in difficult industrial or reuse applications. This process would be used in two ways, 1) as Makeup treatment or 2) in a wastewater recovery configuration.

RO would be used to directly treat cooling tower makeup, steam generator makeup and mirror washing water in alternatives 2 and 5, and would be used to treat cooling tower blowdown to recover used water and reduce overall wastewater volume either for disposal or as a pretreatment to an evaporator in Alternatives 2, 3 and 5.

EVAPORATOR/CRYSTALLIZERS

This process would be used to reduce wastewater volume to essentially zero. In the evaporator, 90% to 95% of the wastewater would be recovered. Brine from the evaporator would be sent to a crystallizer to further recover water. Waste from the crystallizer would be in the form of highly concentrated salt brines that would crystallize to solid form for offsite disposal. This process would be used in Alternatives 4 and 5. A recovery RO would be used to pre-concentrate the wastewater stream to the evaporator as shown in Alternative 5.

WATER TREATMENT ALTERNATIVES

As a means of conserving high quality (fresh) onsite groundwater, staff has analyzed alternatives to using 100% fresh groundwater. In the analysis, five treatment alternatives were evaluated utilizing offsite brackish water (See **Soil & Water Table D2**). All of the alternatives would utilize well water from a brackish makeup source. The water is considered brackish because its total dissolved solids (TDS) content is at least twice that of onsite well water (1,000 mg/l versus 500 mg/l). The brackish aquifer is accessible at the southwest corner of Koehn Lake approximately 5 miles from the project site. It was assumed that four wells would be required to supply BSEP needs. In all of the alternatives, well water would be transported to the site via a 12-inch or 14-inch pipeline (depending on water demand).

Five water treatment alternatives have been identified and analyzed to determine the most effective alternatives to using fresh on-site groundwater. These five alternatives are shown on **Soil and Water Table D2** and discussed below:

Soil & Water Table D2
Offsite Brackish Water Alternatives

	SAC-SBA	Makeup RO	Recovery RO	Evap/Crys	Evap Ponds
Alternative 1	X				X
Alternative 2	X		X		X
Alternative 3		X	X		X
Alternative 4	X			X	
Alternative 5		X	X	X	

ALTERNATIVE 1

Alternative 1 utilizes brackish water from offsite wells for plant needs, e.g. cooling tower makeup, closed cooling system makeup, steam generator makeup, mirror washing, etc. Steam generator blowdown and plant drains would be recycled to the cooling tower. That is the same process proposed by BSEP. In Alternative 1, well water from onsite wells would still be used for potable needs. Plant wastewater would be sent to an evaporation pond for final disposal. The evaporation ponds needed in Alternative 1 would be about 15% larger than those proposed by BSEP because more wastewater would be generated by the SAC-SBA treating brackish water.

ALTERNATIVE 2

This alternative combines Alternative 1 (SAC-SBA) with a recovery RO to reduce the cooling tower blowdown portion of the wastewater stream. MF would be used as pretreatment for the recovery RO. The evaporation ponds would be slightly smaller than the ponds proposed by BSEP.

ALTERNATIVE 3

In this alternative, offsite water would be treated with MF and RO prior to storage in the Process Water Tank (replacing SAC-SBA). A portion of cooling tower blowdown would also be recovered via RO prior to discharge to evaporation ponds. MF would be used as pretreatment for the makeup and recovery RO. Steam generator blowdown and plant drains would be recycled to the cooling tower. RO permeate would be recovered to the cooling tower. This alternative would generate more wastewater than Alternatives 1 or 2 and would require significantly larger evaporation ponds.

ALTERNATIVE 4

This alternative combines Alternative 1 (SAC-SBA) with an evaporator/crystallizer and would essentially eliminate a liquid waste stream. There would be no evaporation pond in this alternative. Crystallizer solid waste would require offsite disposal. Steam generator blowdown and plant drains would be recycled to the cooling tower. Cooling tower blowdown and SAC-SBA wastewater would be fed to the evaporator/crystallizer. Distillate from the evaporator/crystallizer would be recovered to the cooling tower.

ALTERNATIVE 5

This alternative combines Alternative 3 (makeup RO/recovery RO) with an evaporator/crystallizer and would essentially eliminate a liquid waste stream, i.e. there would be no evaporation pond in this alternative. Crystallizer solid waste would require offsite disposal. Steam generator blowdown and plant drains would be recycled to the cooling tower. Cooling tower blowdown and makeup RO wastewater (known as reject) would be fed to the evaporator/crystallizer. Distillate from the evaporator/crystallizer would be recovered to the cooling tower.

Alternatives 4 and 5 would be the only Alternatives employing treatment options that would require offsite waste disposal.

Soil & Water Table D3 provides a comparative summary of using onsite fresh water versus using offsite brackish water for BSEP makeup. The analysis was based on typical summer conditions. Note the evaporation pond sizing for the BSEP-proposed treatment.

Wastewater sources include cooling tower blowdown, steam generator blowdown, plant drains, water treatment waste streams, etc. Cooling tower blowdown and SAC-SBA neutralized wastewater would be sent to three 8.3 acre evaporation ponds. Steam generator blowdown and plant drains would be recycled to the cooling tower. The applicant claims that the ponds are sized to accommodate all solids residue generated throughout the life of the plant.

The treatment process proposed by BSEP was driven by the PM10 requirements that would be placed on the cooling tower by the Air Quality Management District. The total dissolved solids (TDS) of the circulating water must be less than 1,600 mg/l to meet the PM10 limit. Also, BSEP plans to operate the cooling tower at 15 cycles of concentration (the ratio of feedwater flow to blowdown flow is 15) to minimize wastewater generation. This also means that the TDS of the makeup water (onsite wells) must be reduced to approximately 100 mg/l. BSEP proposes using SAC-SBA ion exchangers to accomplish this. SAC-SBA vessels contain ion exchange resin specifically designed to remove cations (positive ions) and anions (negative ions) from water.

The SAC and SBA vessels have a fixed capacity to remove ions, and therefore, must be removed from service frequently and regenerated. This is accomplished by passing dilute sulfuric acid through the SAC vessel (strong acid cation) and dilute sodium hydroxide through the SBA vessel (strong base anion). Water treatment waste, which can have very high or low pH, will require neutralization prior to disposal.

In the applicant's water balance for typical annual conditions, they show a wastewater rate to the evaporation ponds of 471 gpm (BS 2008a, Section 2, Figure 2-13). This consists primarily of cooling tower blowdown and wastewater from water treatment. They plan to operate at an annual 26.5% capacity factor (94% capacity factor during daylight periods). Adjusting wastewater flow to a 24-hour operating basis, flow to the evaporation ponds would be 125 gpm (471 gpm x 26.5%). In this scenario, all wastewater disposal ponds, as designed, would have to operate for the entire year to accommodate this flow. Stated another way, the evaporation rate from the ponds would have to be 97 inches per year.

Evaporation pan data for this area is about 120 inches per year. Pan data is a measure of net evaporation rate and is determined with a National Weather Service Class A pan (measuring 48" diameter x 10" deep). Evaporation rate for small ponds[12] is calculated as follows:

$$Evaporation\ Rate = k_1\ x\ k_2\ x\ Class\ A\ Pan\ Evaporation\ Rate$$

Where k_1 is the pan coefficient and k_2 is the salinity coefficient.[13] For evaporation ponds, a small pond pan coefficient of 0.7 should be used. The salinity factor can range from 1 (insignificant salt concentration) to 0.7 concentrated brines. It could be argued that the brine in the BSEP ponds will reach saturation, i.e. all the salt (as ions) that enters the pond will saturate and start to precipitate. If a midpoint k_2 factor of 0.85 is used, the corrected evaporation rate would be approximately 72. The BSEP ponds are marginally sized to contain expected flow and a fourth pond will likely be required. Also, if water use in the plant is greater than that described in the water balance[14], additional

[12] These could be naturally formed ponds, wastewater evaporation ponds, solar brine ponds, etc.

[13] Linsley, R. K. and Franzini, J. B., 1972, *Water Resources Engineering,* 2nd edition, McGraw-Hill Inc.,
New York, New York.

[14] Figure 2 in the applicant's Project Description.

pond area will be required. Staff calculated a pond size (utilizing the criteria discussed above) of 43.5 acres versus the 25 acres identified in the BSEP project description.

Soil & Water Table D3
Water Treatment Summary

Typical Summer Conditions Basis

		Offsite Wells - Koehn Lake Source Water				
	BSEP Onsite Wells SAC-SBA	Alternative 1 SAC-SBA	Alternative 2 SAC-SBA Recov RO	Alternative 3 MU- RO Recov RO	Alternative 4 SAC-SBA Evap-Crys	Alternative 5 MU-Recov RO Evap-Crys
Water Demand - Instantaneous						
Onsite Wells Demand, gpm	4,038	5	5	5	5	5
Koehn Lake Water Demand, gpm	N/A	4,086	3,772	3,959	3,463	3,480
Total Wastewater, gpm	572	650	565	801	0	0
Water Demand - Annual Average Conditions						
Annual Capacity Factor	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
Onsite Wells Demand, gpm	1,070	5	5	5	5	5
Koehn Lake Water Demand, gpm	N/A	1,083	1,000	1,049	918	922
Onsite Wells Demand, AF/yr	1,726	8.1	8.1	8.1	8.1	8.1
Koehn Lake Water Demand, AF/yr	N/A	1,747	1,612	1,692	1,480	1,488
Total Wastewater, gpm	152	172	150	212	0	0
Evap Pond, acres[1]	43.5	49.4	42.9	60.8	0	0

Notes.....
1. BSEP project evap pond size was altered from that presented in the AFC based on CEC staff calculations.

COST ANALYSIS

Soil & Water Table D4 presents a cost analysis of using fresh groundwater obtained from BSEP onsite wells versus obtaining and using offsite brackish water. From a capital perspective, Alternative 1 (SAC-SBA) and Alternative 2 (SAC-SBA with recovery RO) are the least costly of the offsite alternatives, and would cost an additional $12.6 million and $12.1 million, respectively. Alternatives 1 and 2 also have the lowest operating cost of the mentioned alternatives, exceeding the BSEP design by $0.8 million per annum. Lastly, when the installed cost is capitalized (amortized at 7% for 20 years), Alternatives 1 and 2 are still the least costly of the five offsite alternatives. However, its annual cost would exceed BSEP costs by $2 million per year.

Again, Alternatives 1 and 2 achieve the goal of using non-potable quality water for project cooling. Given the budget level of analysis, the costs of these alternatives are quite close and should be considered equivalent.

Soil & Water Table D4
Water Treatment Summary & Cost Analysis

Typical Summer Conditions Basis

	BSEP	Offsite Wells - Koehn Lake Source Water				
	Onsite Wells	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5
	SAC-SBA	SAC-SBA	SAC-SBA Recov RO	MU RO Recov RO	SAC-SBA Evap-Crys	MU-Recov RO Evap-Crys
Equipment & Evap Pond Installed Cost						
SAC-SBA	$20,610,000	$20,610,000	$20,610,000	N/A	$20,610,000	N/A
MU-Recovery RO	N/A	N/A	$3,380,000	$23,840,000	N/A	$21,160,000
Evaporator Crystallizer	N/A	N/A	N/A	N/A	$33,750,000	$36,190,000
Common Tankage & Pumping	$11,140,000	$11,270,000	$10,520,000	$10,970,000	$9,770,000	$9,810,000
Water Treatment Subtotal	$31,750,000	$31,880,000	$34,510,000	$34,810,000	$64,130,000	$67,160,000
Evaporation Pond	$10,960,000	$12,460,000	$10,820,000	$15,340,000	N/A	N/A
Total Water & Wastewater	$42,710,000	$44,340,000	$45,330,000	$50,150,000	$64,130,000	$67,160,000
Pipeline from Koehn Lake						
4 Wells	N/A	$880,000	$880,000	$880,000	$880,000	$880,000
Pump Station	N/A	$3,080,000	$3,000,000	$3,050,000	$2,910,000	$2,910,000
5 Mile Carbon Steel Pipeline	N/A	$6,970,000	$5,580,000	$6,970,000	$5,580,000	$5,580,000
Total	N/A	$10,930,000	$9,460,000	$10,900,000	$9,370,000	$9,370,000
Total Installed Water Treatment Costs	$42,710,000	$55,270,000	$54,790,000	$61,050,000	$73,500,000	$76,530,000
	Base	$12,560,000	$12,080,000	$18,340,000	$30,790,000	$33,820,000
Total Annual Operating Costs	$1,215,000	$2,056,000	$2,075,000	$2,235,000	$3,781,000	$4,215,000
	Base	$841,000	$860,000	$1,020,000	$2,566,000	$3,000,000
Capitalized Equipment Costs[1]	$4,032,000	$5,218,000	$5,172,000	$5,763,000	$6,938,000	$7,224,000
	Base	$1,186,000	$1,140,000	$1,731,000	$2,906,000	$3,192,000
Annual Operating & Capital Cost	$5,247,000	$7,274,000	$7,247,000	$7,998,000	$10,719,000	$11,439,000
	Base	$2,027,000	$2,000,000	$2,751,000	$5,472,000	$6,192,000

Notes.....
1. Capitalized at 7% per year for 20 years.

Soil & Water Table D5 shows the cost sensitivity of increased TDS in the offsite wells. Refer to the following for an analysis comparing the costs of offsite well alternatives if well water TDS were 2,500 mg/l instead of 1,000 mg/l. The operating costs of Alternatives 1, 2 and 4, which utilize SAC-SBA treatment, would increase by 61.0% to 67.9%. The additional ion loading would require larger and/or more ion exchange vessels. Alternative 3 (makeup RO/recovery RO) operating costs increased by 3%. The operating pressure of the RO equipment would be higher at higher feed TDS. Equipment costs also increased for Alternatives 1, 2 and 4 by 45.9% to 48.8%. Alternative 3 will be carried forward in this evaluation (along with Alternatives 1 and 2) because it offers more operating flexibility from an operating and capital viewpoint.

Soil & Water Table D5
Water Treatment Cost Comparison – Increase in TDS from Offsite Wells

Typical Summer Conditions Basis

	BSEP Onsite Wells SAC-SBA	Koehn Lake TDS, mg/l	Offsite Wells - Koehn Lake Source Water Alternative 1 SAC-SBA	Alternative 2 SAC-SBA Recov RO	Alternative 3 MU RO Recov RO	Alternative 4 SAC-SBA Evap-Crys	Alternative 5 MU-Recov RO Evap-Crys
Annual Operating Costs	$1,215,000	1,000	$2,056,000	$2,075,000	$2,235,000	$3,781,000	$4,215,000
		2,500	$3,452,000	$3,341,000	$2,302,000	$6,228,000	$4,750,000
		Pct Change	67.9%	61.0%	3.0%	64.7%	12.7%
Install Equipment Cost	$42,710,000	1,000	$55,270,000	$54,790,000	$61,050,000	$73,500,000	$76,530,000
		2,500	$81,350,000	$81,550,000	$62,590,000	$107,200,000	$78,510,000
		Pct Change	47.2%	48.8%	2.5%	45.9%	2.6%
Annual Op & Cap Cost	$5,247,000	1,000	$8,767,000	$8,625,000	$7,998,000	$12,140,000	$11,439,000
		2,500	$11,131,000	$11,039,000	$8,211,000	$16,347,000	$12,161,000
		Pct Change	27.0%	28.0%	2.7%	34.7%	6.3%

COOLING ALTERNATIVES

BSEP evaluated three Air Cooled Condenser (ACC) dry cooling alternatives (refer to Worley Parsons report “FPLE Beacon Solar Energy Project Dry Cooling Evaluation”, dated February 1, 2008). The report evaluated three ITD scenarios (35 °F, 40 °F and 45 °F). Each ITD scenario yields a slightly different operating profile. For evaluation purposes, the 40 °F scenario was compared to wet cooling alternatives, i.e. the BSEP base case and Alternatives 1, 2 and 3. In the Worley Parsons study, the cost for solar arrays was increased to provide 250 MW (i.e. same as base case) on the hottest summer day to offset energy use for ACC.

A summary of cooling system comparisons is presented in **Soil & Water Table D6**. Note that the cooling system (cooling tower) costs remain the same for the base case and Alternatives 1, 2 and 3. After combining the costs for the cooling systems (wet and dry), water treatment and additional solar arrays, the BSEP base case is the lowest estimated capital cost followed by Alternatives 1, 2 and 3 (in that order) and dry cooling. As can be seen in this analysis, the additional solar arrays strongly affect the capital cost comparisons. The annual operating costs were calculated by adding power for the wet and dry cooling system to the annual cost for water treatment. Other power costs (outside the cooling loop) were considered equivalent. Of note, the dry cooling alternative has the lowest operating costs of all the Alternatives and is $403,000 less than the BSEP base case.

Soil & Water Table D6
Cooling System Cost Comparison

Cooling System Comparison Summary					
Typical Summer Conditions Basis					
	BSEP Base Case	Alternative 1 Offsite Wells SAC-SBA	Alternative 2 Offsite Wells SAC-SBA Recov RO	Alternative 3 Offsite Wells MU/Recov RO	ACC 40F ITD
Cooling System					
Cooling Tower Cells	11				N/A
ACC Cells	N/A				40
Power Requirements					
Fan Power, HP	250				200
Circ Pump Power, HP	2509				N/A
Total Power, HP	5259				8000
Total Power, kw	3918				5960
Average Op Capacity	26.5%				26.5%
Power, kw-hr/year	9,096,000				13,836,000
Power Cost, $/year	$1,364,400	$1,364,400	$1,364,400	$1,364,400	$2,075,400
Cooling System Costs					
HTF Pumps	$3,000,000				$3,000,000
BFW Pumps	$2,300,000				$2,400,000
SG Heat Exchanger	$12,500,000				$14,100,000
Additional Solar Arrays[1] (installed)	Base				$53,000,000
Cooling Tower	$4,275,000				N/A
CT Basin	$1,500,000				N/A
Circ Water Pumps	$600,000				N/A
Surface Condenser	$3,500,000				N/A
Circ Water Piping	$1,300,000				N/A
Circ Water Piping Install	$520,000				N/A
ACC Equipment	N/A				$36,900,000
ACC Install	N/A				$11,500,000
Closed Cycle Aux Cooler	N/A				$450,000
Total Cooling System Cost	$29,495,000	$29,495,000	$29,495,000	$29,495,000	$121,350,000
Water Treatment Costs	$42,710,000	$55,270,000	$54,790,000	$61,050,000	$4,600,000
Total System Cost	$72,205,000	$84,765,000	$84,285,000	$90,545,000	$125,950,000
	Base	$12,560,000	$12,080,000	$18,340,000	$53,745,000
Annual Operating Costs					
Water Treatment	$1,215,000	$2,056,000	$2,075,000	$2,235,000	$101,000
Cooling System Power	$1,364,400	$1,364,400	$1,364,400	$1,364,400	$2,075,400
Total Operating Cost[2]	$2,579,400	$3,420,400	$3,439,400	$3,599,400	$2,176,400
	Base	$841,000	$860,000	$1,020,000	-$403,000
Capitalized Equipment Costs[3]	$6,820,000	$8,010,000	$7,960,000	$8,550,000	$11,890,000
	Base	$1,190,000	$1,140,000	$1,730,000	$5,070,000
Annual Operating & Capital Costs	$9,399,400	$11,430,400	$11,399,400	$12,149,400	$14,066,400
	Base	$2,031,000	$2,000,000	$2,750,000	$4,667,000

Notes.....

1. Costs extracted from Worley Parsons report, "FPLE - Beacon Solar Energy Project Dry Cooling Evaluation" dated Febr February 1, 2008.
2. Water treatment costs plus cost for cooling system power. All other power costs were assumed to be equivalent.
3. Capitalized at 7% per year for 20 years.

Typical Summer Conditions Basis	BSEP Base Case	Alternative 3 Offsite Wells MU/Recov RO	ACC 40F ITD
Cooling System			
Cooling Tower Cells	11		N/A
ACC Cells	N/A		40
Power Requirements			
Fan Power, HP	250		200
Circ Pump Power, HP	2509		N/A
Total Power, HP	5259		8000
Total Power, kw	3918		5960
Average Op Capacity	26.5%		26.5%
Power, kw-hr/year	9,096,000		13,836,000
Power Cost, $/year	$1,364,400	$1,364,400	$2,075,400
Cooling System Costs			
HTF Pumps	$3,000,000		$3,000,000
BFW Pumps	$2,300,000		$2,400,000
SG Heat Exchanger	$12,500,000		$14,100,000
Additional Solar Arrays[1] (installed)	Base		$53,000,000
Cooling Tower	$4,275,000		N/A
CT Basin	$1,500,000		N/A
Circ Water Pumps	$600,000		N/A
Surface Condenser	$3,500,000		N/A
Circ Water Piping	$1,300,000		N/A
Circ Water Piping Install	$520,000		N/A
ACC Equipment	N/A		$36,900,000
ACC Install	N/A		$11,500,000
Closed Cycle Aux Cooler	N/A		$450,000
Total Cooling System Cost	$29,495,000	$29,495,000	$121,350,000
Water Treatment Costs	$42,710,000	$61,050,000	$4,600,000
Total System Cost	$72,205,000	$90,545,000	$125,950,000
	Base	$18,340,000	$53,745,000
Annual Operating Costs			
Water Treatment	$1,215,000	$2,235,000	$101,000
Cooling System Power	$1,364,400	$1,364,400	$2,075,400
Total Operating Cost[2]	$2,579,400	$3,599,400	$2,176,400
	Base	$1,020,000	-$403,000
Capitalized Equipment Costs[3]	$6,820,000	$8,550,000	$11,890,000
	Base	$1,730,000	$5,070,000
Annual Operating & Capital Costs	$9,399,400	$12,149,400	$14,066,400
	Base	$2,750,000	$4,667,000

Notes.....

1. Costs extracted from Worley Parsons report, "FPLE - Beacon Solar Energy Project Dry Cooling Evaluation" dated February 1, 2008.
2. Water treatment costs plus cost for cooling system power. All other power costs were assumed to be equivalent.
3. Capitalized at 7% per year for 20 years.

Lastly, the Worley Parsons study determined that the net output for the 40 °F ITD ACC would be 7.50% less than that of the base case. The base case would include the BSEP proposed cooling configuration or Alternative 3 (offsite wells with makeup and recovery RO). At high ambient dry bulb temperatures (summer conditions), the ACC cannot cool as efficiently as wet cooling resulting in higher condenser backpressure and reduced turbine output. **Soil & Water Table D7** provides a comparison of annual net output for the wet and dry alternatives. The difference in generating output is an indirect measure of ACC cooling efficiency relative to wet cooling.

Soil & Water Table D7

Net Output Comparisons

	BSEP Wet Cooling	ACC 40° F ITD
Design Point Ambient Temperature, F	68 °F WB	103.5 °F DB
Design Point Backpressure, "Hg	2.1	7.1
Plant Output, MW_{Net}	250	250
Annual Average Backpressure, "Hg	1.5	2.0
Estimated Annual Output, MW-hr	602,527	557,365
Est Annual Output Difference, MW-hr	Base	45,162
Pct Difference to Base	Base	-7.50%

The design requirement for the ACC is rigorous in that the ACC must meet design point summer conditions. To compensate for reduced efficiency and to achieve 250 MW net output based at a design point of 103.5 °F (DB temperature)[15], the applicant increased the size of the solar array. Additionally, the ACC alternatives were sized to provide 2" mercury (Hg) of backpressure based on annual average conditions as compared to the 1.5" Hg expected for wet cooling. The loss of output was calculated based on the difference in annual average backpressure, i.e. 1.5" Hg for wet cooling versus 2" Hg for dry cooling. The installed cost (and presumably collector area) of the solar arrays would have to be increased by 12.9 percent to achieve their design requirements.

The applicant should review their design criteria to minimize the impact on the solar array. For example for slightly lower design points, review ACC size versus required solar filed array. Incrementally increasing the size of the ACC (e.g. 36 fans to 40 fans) is much less costly than increasing the size of the solar array.

CONCLUSIONS

1. The BSEP waste disposal evaporation ponds are marginally sized and a fourth pond will likely be required. Also, if water use in the plant is greater than that described in the water balance, additional pond area will be required.

2. Alternative 1 (SAC-SBA), Alternative 2 (SAC-SBA with recovery RO) and Alternative 3 (makeup RO/recovery RO) are viable non-potable (high TDS) water options in lieu of using onsite high-quality fresh groundwater. Alternative 3 is much less sensitive to higher TDS groundwater available from offsite wells.

[15] The design temperature is the average of the July, August and September ASHRAE summer peak 2% dry bulb (DB). It is within the 0.4% and 1% annual occurrences of high temperatures for this area.

3. The applicant should review their design criteria for the ACC. The rigorous design point (103.5 ºF DB) forces them to expand the collector array area by 12.9 percent. The applicant should review their design criteria to minimize the impact on the solar array. For example, for slightly lower design points, ACC size versus required solar filed array should be evaluated.

TRAFFIC AND TRANSPORTATION

David Flores

SUMMARY OF CONCLUSIONS

The Beacon Solar Energy Project (BSEP) would be consistent with the Circulation Element in the Kern County General Plan, local circulation plans and policies and all other applicable laws, ordinances, regulations, and standards. The project would not have a significant adverse impact on the local and regional road/highway network. During the construction and operation phases, local roadway and highway demand resulting from the daily movement of workers and materials would not increase beyond significance thresholds established by Kern County. During the operational phase, the project would not adversely affect local roads or aviation operations associated with any airport flight traffic.

INTRODUCTION

In the traffic and transportation analysis, staff addresses the extent to which the project may impact the transportation system in the local area. This analysis includes the identification of 1) the proposed roads and routings to be used for construction and operation; 2) potential traffic-related problems associated with the use of those routes by construction workers and truck deliveries; 3) the anticipated encroachment upon public rights-of-way during the construction of the proposed project and associated facilities; 4) the frequency of trips and probable routes associated with the delivery of hazardous materials; and 5) the possible effect of project operations on local airport flight traffic.

In addition to assessing potential project related impacts, staff has reviewed the applicable laws, ordinances, regulations, and standards (LORS) to determine compliance. The LORS that govern the project are listed below in **Traffic and Transportation Table 1**, followed by a discussion of the potential impacts related to traffic operations and safety hazards resulting from the construction and operation of the BSEP.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Traffic and Transportation Table 1
Laws, Ordinances, Regulations, and Standards

Applicable LORS	Description
Federal:	
Title 14, Code of Federal Regulations (CFR) Chapter 1, Part 77	Includes standards for determining obstructions in navigable airspace. Sets forth requirements for notice to the Federal Aviation Administration of certain proposed construction or alteration. Also, provides for aeronautical studies of obstructions to air navigation to determine their effect on the safe and efficient use of airspace.
Title 49, Subtitle B	Includes procedures and regulations pertaining to interstate and intrastate transport (includes hazardous materials program procedures) and provides safety measures for motor carriers and motor vehicles that operate on public highways.
State:	
California Vehicle Code, 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 Government Code, Sec.65352, 65940, and 65944	Requires evaluation of compatibility with military activities for any land use proposal located near a military installation or airspace.
California Public Utilities Commission General Order 75, Section 7.1	Pursuant to Public Utilities Code Section 7537, the Commission has the authority to determine the necessity for any private at-grade crossing and the place, manner, and conditions under which the at-grade crossing shall be constructed and maintained, and to fix and assess the cost and expense thereof.
Local:	
Kern County General Plan Circulation Element, Sec. 2.3.2 & 2.3.3	Establishes level of service (LOS) D or better as minimum acceptable standard on County roadways, and a LOS C on State or Federal Highways.
Kern County Circulation Element	Addresses long-term planning goals and procedures for transportation infrastructure system quality: standards and procedures for air transportation: and transportation safety in Kern County.

Kern County Circulation Element-Cont.	Kern County must assure protection of road right-of-way for efficient management of circulation. Goals 3: Protecting corridors for future transportation facilities is most important transportation planning activity in any high growth area. Goal 4: To reserve right–of- way to meet future road needs that result from development allowed by land use plans.

SETTING

The BSEP site is located in a remote section of Kern County, approximately 4 miles north of the northern boundary of California City. Regional access to the area is limited to State Route 14 (SR-14). A mayor portion of the roadways consist of unpaved local roadways extending east and west from SR-14. **Traffic and Transportation Figure 1, Regional Transportation System,** shows the region surrounding the project site. Transportation figures are located at the end of this analysis.

CRITICAL HIGHWAYS AND ROADS

SR-14 is a north-south freeway that runs from the eastern side of the Sierra Nevada Mountain Range from the Los Angeles basin to US 395 near the community of Inyokern.

California Department of Transportation (Caltrans) records show average daily traffic volume on SR-14 in the project area (north of California City Boulevard) at 6,600 vehicles per day and 19,000 vehicles per day south of SR-85 (Caltrans 2007).

The local roadways in the area include California City Boulevard, and the Randsburg cutoff which is a east-west roadway that provides the most direct route to the proposed project site. It is classified as a major arterial and connects to the regional freeway system via an interchange with the SR-14 freeway to the north and SR-58 freeway to the south.

LEVEL OF SERVICE

Level of Service (LOS) is a qualitative measure describing operational conditions within a traffic stream. The term 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, travel time, and delay. The *Highway Capacity Manual*[1] defines six levels of service for roadways or intersections ranging from LOS A representing the best operating conditions and LOS F, the worst.

Traffic and Transportation Table 2 provides existing daily and peak traffic volume and LOS in the project area. Plant construction and operation traffic would use the existing local roadways, including SR-14 and SR-58, which are the principal highways in the

[1] National Research Council, *Highway Capacity Manual, Third Edition*, 1994.

area and are LOS A on a daily basis. Access into the project site will be from SR-14. The access point will be determined by Caltrans as they restrict the number of access points from the state highway.

Traffic and Transportation Table 2
Baseline Peak Hour Roadway Traffic Volumes Design Capacities, and Levels of Service (Without the Project)

	Existing Conditions[1]				Year 2011 Conditions[2]			
Roadway/ Segment	**Travel Lanes**	**Volume**	**Capacity[3]**	**LOS**	**Travel Lanes**	**Volume**	**Capacity[3]**	**LOS**
SR-14 north of Project site	2	345[4]	2,000	A	2	355	2,000	A
SR-14 at Project Site	4	345[4]	6,800	A	4	355	6,800	A
SR-14 south of Project Site	2	345[4]	2,000	A	2	355	2,000	A
SR-14 south of Mojave	4	2,050	6,800	A	4	2,345	6,800	A
SR-58 west of SR-14	4	1,900	6,800	A	4	2,255	6,800	A
SR-58 east of SR-14	4	1,850	6,800	A	4	2,345	6,800	A

1 Source-Caltrans,2007
2 Year 2006 traffic volumes expanded to Year 2011 (estimated construction completion) at historical rates Year 2000 to 2006 (1.28-3.76 percent/year depending on location.
3 Approximate two-way capacity in vehicles per hour.
4 Wilson Engineering Field County, February 2008.

AIRPORTS

The nearest airport facility is the California City Municipal Airport, located approximately six miles south of the proposed project site. There are three other airports in the region, including the Mojave Air and Space Port located approximately fifteen miles southwest of the project site, the Edwards Air Force Base located approximately twenty miles to the south, and the Naval Weapons Station China Lake facility located approximately forty miles northeast of the project site.

PUBLIC TRANSPORTATION

The following is a list of public transit providers in the general area around the proposed BSEP site:

- Currently there are no bike paths in the area of the project site. Bicycle and pedestrian circulation rely on the shoulders of the rural highway and county roads, but are not allowed on freeways.
- Regional transit in the area is provided by Kern Regional Transit with the Boron Mojave Route, East Kern Express, and the Mojave-Ridgecrest Route. The following are the route details:
- Boron-Mojave Route: Service is provided on Wednesday only between the communities of Boron, North Edwards, and Mojave.
- East Kern Express: Service is provided Monday through Saturday between the communities of Bakersfield, Keene, Tehachapi, Mojave, Rosamond, and Lancaster.
- Mojave-Ridgecrest Route: Service is provided between Mojave and California City Monday through Saturday. Intercity service is provided between the communities of Ridgecrest, Inyokern, and Mojave on Monday, Wednesday, and Friday.
- Dial-A-Ride service is also provided in the communities of Mojave, Tehachapi, and Rosamond. Service is available Monday, Wednesday, and Friday.

There are no school bus routes or stops within the routes that would be used by the workforce going to the project site or along the truck routes proposed for use during construction of the project.

RAILROADS

The applicant has indicated that during construction an established rail line off-loading area would be used for delivery of heavy equipment. The railroad off-loading site is located in the community of Mojave. It will be utilized during BSEP construction for the delivery of several pieces of major generation equipment, which will then be transported by truck to the project site.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

According to Appendix G of the California Environmental Quality Act (CEQA) Guidelines, a project may have a significant effect on traffic and transportation if the project 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 a substantial increase in either the number of vehicle trips, the volume to capacity ratio on roads, or congestion at intersections);
- exceed, either individually or cumulatively, a level of service standard 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 or 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);
- result in inadequate emergency access; or
- result in inadequate parking capacity; or conflict with adopted policies, plans, or programs.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Construction Impacts and Mitigation

When evaluating a project's potential impact on the local transportation system, staff uses LOS determinations as the foundation on which to base its analysis. The following discussion identifies potential traffic impacts associated with the construction of the BSEP and provides an explanation of the impact conclusion.

The Application for Certification (AFC) provides an analysis of projected traffic conditions with the addition of project construction traffic trips. Project construction is expected to take 25 months. All plant construction workers would park on a 6-acre parcel of land directly west of the BSEP site (BSEP 2008a, p. 5.13-11). This would also serve as a laydown area for materials and equipment (see **Traffic and Transportation Figure 2**). Staff has determined that the parking area is adequate for the number of construction workers involved in the project, based on the 6 acres that will be set aside for construction worker parking and laydown area.

Construction Workforce Traffic

To determine the amount of vehicle trips to the project site during average and peak construction, the applicant assumed that workers would commute alone during the morning and afternoon peak intervals (6:00 a.m. to 9:00 a.m. and 4:00 p.m. to 6:00 p.m.). The average number of construction workers would be approximately 400, while the peak workforce would consist of 836 workers during month 15 of the construction period. Considering that some degree of carpooling would occur, the applicant assumed 880 one-way daily trips during peak construction. Given experience with previous projects, staff believes that the estimated construction traffic trips and assumptions about peak construction activity are reasonable. Based on regional demographics and availability of skilled laborers, the construction workers would probably come from Kern County. However, staff believes that some workers could come from San Bernardino and Los Angeles County.

Construction Truck Traffic

Construction of the generating plant would require the use and installation of heavy equipment and associated systems and structures. Heavy equipment would be used throughout the construction period, including trenching and earthmoving equipment, forklifts, cranes, cement mixers, and drilling equipment. A passenger car equivalent (PCE) factor of three cars per truck was used to determine the traffic impacts of trucks and heavy equipment deliveries (National Research Council 1994). Project construction is expected to require 15 trucks on average and 19 trucks during peak construction per day (BSEP 2008a). In-bound and out-bound truck traffic would arrive and depart the project site using the same route as construction workers.

Total Construction Traffic

The total peak construction traffic impact would be from 836 worker trips plus 20 truck and delivery trips, or 1,712 one-way vehicle trips. Staff is proposing Condition of Certification **TRANS-2** to repair any damage to Neuralia Road and California City Boulevard from construction traffic, particularly from heavy trucks.

As reflected in **Traffic and Transportation Table 3**, the project construction related increases in traffic will be limited as project impacts would be dispersed over a number of routes, not causing a degradation of existing peak hour LOS. Roadways to the project site are forecasted to continue to operate at LOS A on the same segments as shown on **Table 2, Freeway/Roadway Segment Level of Service Existing Conditions** during the a.m. and p.m. peak hours. None of the study segment's LOS would deteriorate to a worse LOS, and would not result in a significant impact.

Traffic and Transportation Table 3
Peak Hour Roadway Volumes, Design Capacities, and Levels of Service
(With Project Related Traffic)

	Year 2011 Conditions with Project Construction Traffic[1]				**Year 2011 Conditions with Project Operations Traffic[2]**			
Roadway/ Freeway	**Travel Lanes**	**Traffic Volume**	**Capacity[3]**	**LOS[1]**	**Travel Lanes**	**Traffic Volume**	**Capacity[3]**	**LOS**
SR-14 - North of Project Site[2]	2	397	2,000	A	2	358	2,000	A
SR-14- At the Project Site[2]	4	1,150	6,800	A	4	402	6,800	A
SR-14- South of the Project Site[2]	2	1,150	2,000	A[4]	2	402	2,000	A
SR-14- South of Mojave[2]	4	2,680	6,800	A	4	2,365	6,800	A
SR-58- West of SR-14[2]	4	2,505	6,800	A	4	2,265	6,800	A
SR-58- East of SR-14[2]	4	2,512	6,800	A	4	2,355	6,800	A

[1] Assumes month 15 peak construction traffic levels with 836 workers
2 Assumes normal future project operations with total work force of 66 employees.

[3] Two-Way capacity in vehicles per hour
[4] Based on volume to capacity ratio, project operations are LOS A. Based on the most recent highway capacity manual methodology for rural two-way highways, which determines LOS based on an estimated percentage of drives having to follow another vehicle under worst case peak conditions, the two-lane segment of SR-14 at the BSEP site could be described as operating at LOS D.
[2] Source: Caltrans, 2005

Linear Facilities

Natural gas would be provided using a new 8-inch diameter gas line connection from the project site an existing Southern California Gas pipeline situated in west of California City. (BSEP 2008a, p. 2-27). Total length of the gas line would be approximately 1.2 miles within the project site, and 16.4 miles outside the plant boundaries. With the off-site portion constructed within the existing county right-of-way, the need for flagmen and proper signage would be addressed under Caltrans and Kern County encroachment permits.

Water for the proposed project would be supplied by 12 groundwater wells on-site with a water storage facility to handle fire protection and domestic use; therefore, no traffic issues would exist for the installation of off-site water pipelines. The western boundary of the 2,012-acre BSEP plant site is located approximately one mile east of the two existing LADWP transmission lines: 1) the Celilio-Sylmar 500 kV DC intertie line and 2) the Inyo-Barren Ridge 230 kV line. The applicant has proposed two, alternative routes. One would involve a route directly from the plant site power block to the Barren Ridge Switching Station, which is approximately 1.6 miles in length.

Option 2 would include a new switching station adjacent to the existing LADWP ROW west of SR-14 on Beacon Solar owned property, and would require approximately 2.3 miles of overhead 230kV transmission line from the power block west to the new switchyard next to the LADWP ROW.

Construction Phase Transport of Hazardous Materials and Waste

Deliveries to the BSEP site would include small quantities of hazardous materials to be used during project construction. The applicant has stated that the delivery/disposal of hazardous materials (15 deliveries per month [BSEP 2008a]) to and from the site, and materials handling on site would be conducted in accordance with all applicable federal and state statutes (see the **Hazardous Materials Management** section of this assessment for more information). The preferred transportation route for hazardous materials delivery would be via SR-14, and possibly SR-58 to access the BSEP site from the south.

School Bus Route

As noted earlier, there are no school bus routes or bus stops near the proposed project or along the proposed worker and truck routes identified in this analysis.

Railroad Crossing

Access to the laydown and parking areas that will be used during construction would require crossing the Union Pacific Lone Pine Branch rail line. Union Pacific representatives will need to be notified regarding necessary upgrades at the railroad crossing to minimize potential conflicts between construction and rail activities. To date, staff is not aware of any attempts by the applicant to contact railroad representatives. Condition of Certification **TRANS-3** requires the applicant to obtain the necessary approvals for their construction of a crossing arm, or other required mitigation requirements.

Access Road and Driveway Improvements

BSEP site access will be provided via a new driveway/access road extending easterly from SR-14 in the northeastern area of the plant site. Condition of Certification **TRANS-1** requires that the applicant work with Caltrans in securing the necessary encroachment permits and constructing the driveway access in accordance with Caltrans requirements.

The Kern County Resource Management Agency submitted a letter dated September 16, 2008 responding to the AFC and their attendance of a public workshop held on August 25, 2008. In their response letter they indicated that existing dedicated right-of-ways exist along the section lines and mid-section lines within the project area. The County's Circulation Element requires the preservation of these open corridors for future roadways.

The County indicated in their letter that to delete these reservations, would require a General Plan Amendment to the Circulation Element, requiring Planning Commission and the Board of Supervisors review and approval. It is anticipated that Planning Commission hearings for this amendment will be heard on April 21, 2009, and shortly thereafter before the Board of Supervisors for final consideration.

Energy Commission staff has indicated their preference is for the applicant to provide a right-of-way access easement along the eastern, northern, and westerly property boundary lines for continued access for maintenance of the overhead transmission lines that evidentially will be relocated from its current location within the project site to the northern edge of the project site. In addition, the right-of-way access road will provide a secondary access for fire protection equipment during an emergency response. See the **LAND USE** section of this analysis for continued discussion of public-right-of way dedications.

Operation Impacts and Mitigation

Employee and Truck Traffic

Operation of the power plant would require a labor force of 66 full-time employees that would generate 132 one-way trips to and from the BSEP site. Other project-related trips (that is, delivery trucks, visitors, and other business-related trips) are expected to be minimal and would occur during regular business hours. Staff assumes that operational workers would follow the same routes as the construction workers. These minor trip additions to surrounding local streets and highways would not significantly affect the LOS of these roads.

Transport of Hazardous Materials and Waste

The transportation and handling of hazardous substances associated with the proposed project could increase roadway hazard potential. Impacts associated with hazardous material transport to the facility could be mitigated to a level of insignificance by compliance with existing federal and state standards established to regulate the transportation of hazardous substances. The applicant intends to comply with all federal and state regulations related to the transportation of hazardous materials (BSEP 2008a, p.5.13-15).

The California Department of Motor Vehicles exclusively licenses all drivers who transport hazardous materials. Drivers are also required to check for weight limits and conduct periodic brake inspections. Commercial truck operators handling hazardous materials are also required to take instruction in first aid and procedures on handling hazardous waste spills. Drivers transporting hazardous waste are required to carry a manifest, which is available for review in the event of a spill, and is reviewed by the California Highway Patrol at inspection stations along major highways and interstates.

The California Vehicle Code and the Streets and Highways Code (sections 31600 through 34510) ensure that the transportation and handling of hazardous materials are done in a manner that protects public safety. Enforcement of these statutes is under the jurisdiction of the California Highway Patrol.

Project operation would require use of hazardous substances including sulfuric acid and cleaning and water treatment chemicals. It is estimated that there would be a maximum of six delivery/service trucks per week. A licensed hazardous waste transporter would haul any hazardous waste from the project site to one of three Class 1 hazardous waste landfills in western Kern County near the communities of Buttonwillow and Kettleman City, and in Imperial County near the community of Westmoreland. The handling and disposal of hazardous substances are also addressed in the **Waste Management, Worker Safety and Fire Protection,** and **Hazardous Materials** sections of this assessment.

Airport Operations

As noted earlier, the closest major airport is the California City Municipal Airport which is approximately 6 miles south of the proposed site. The existing flight pattern does not bring aircraft at low altitude over the project site. The steam turbine generator would be 55 feet high and the cooling tower would be 45 feet high (BSEP 2008a, pg.5.15-9). The transmission line support towers would average around 79 feet high, but a small number of transmission towers near the project facilities will be 110 feet. These structures would not penetrate navigable airspace for any airport.

As indicated in the AFC (BSEP 2008A, pg. 5.13-17), because of the remoteness of the project from the nearest civilian airport (six miles), the project would not conflict with civilian aircraft operations, however the applicant has filed a Federal Aviation Administration (FAA) Form 7460 to determine if any additional requirements may be required.

Ground Hugging Plumes

SACTI calculations were performed for AEP and no ground hugging plumes are predicted under the range of cooling tower operations provided by the applicant. Therefore, based on the SACTI model there would appear to be no impacts from the plumes to ground traffic in the project area.

Emergency Services Vehicle Access

The Kern County Fire Department would provide 24-hour fire protection and emergency medical services to the BSEP site. The nearest fire station is in the California City, about ten miles from the project site. Emergency service vehicles would reach the project site via the access road off SR-14 or Neuralia Road. For a more detailed discussion of emergency services concerning adequate ingress/egress serving the facility, see the **Worker Safety and Fire Protection** section of this assessment.

CUMULATIVE IMPACTS

No cumulative projects have been identified in the project vicinity that would create significant traffic impacts when considered together with the BSEP. The nearest known projects are the Pine Tree Wind Development Project, which is located approximately six miles west of the BSEP site and the LADWP Barren Ridge-Castaic Switching Station about 1.5 miles south of the plant site and extends south to Los Angeles County. Due to the distance from the BSEP site and the absence of significant traffic impacts associated with either project, cumulative impacts to existing traffic patterns and County circulation plans and policies would be less than significant. It should also be noted that Caltrans has no highway improvement proposals in this general area.

Staff has considered the minority populations (as identified in **Socioeconomics Figure 1**) and low income populations in its impact analysis. There are no significant direct or cumulative traffic and transportation impacts, and therefore, no environmental justice issues.

COMPLIANCE WITH LORS

The applicant has stated its intention to comply with all applicable LORS (BSEP 2006a, section 5.11.5). Staff has concluded that the project as proposed would comply with relevant LORS. **Traffic and Transportation Table 3** presents the project's conformance with all applicable LORS.

TRAFFIC & TRANSPORTATION Table 3
Project Compliance with Adopted Traffic and Transportation LORS

Applicable LORS	Description
Federal: Title 14, Code of Federal Regulations (CFR) Chapter 1, Part 77	Includes standards for determining obstructions in navigable airspace. Sets forth requirements for notice to the Federal Aviation Administration of certain proposed construction or alteration. Also, provides for aeronautical studies of obstructions to air navigation to determine their effect on the safe and efficient use of airspace.
	Consistent: The nearest civilian airport is six miles away, therefore none of the project's structures would not penetrate any navigable airspace. The applicant will file a Notice of Proposed Construction or Alteration with the FAA to determine if any additional requirements are necessary.
Title 49, Subtitle B	Includes procedures and regulations pertaining to interstate and intrastate transport (includes hazardous materials program procedures) and provides safety measures for motor carriers and motor vehicles that operate on public highways.
	Consistent: 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).
State: California Vehicle Code, 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.
	Consistent: Enforcement is provided by state and local law enforcement agencies and through ministerial state agency licensing and permitting and/or local agency permitting.
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.
	Consistent: Enforcement is provided by state and local law enforcement and through ministerial state agency licensing and permitting and/or local agency permitting.

California Public Utilities Commission General Order 75, Section 7.1	Pursuant to Public Utilities Code Section 7537, the Commission has the authority to determine the necessity for any private at-grade crossing and the place, manner, and conditions under which the at-grade crossing shall be constructed and maintained, and to fix and assess the cost and expense thereof.
	<u>Consistent</u>: The applicant in consultation with the California Public Utilities Commission and Union Pacific Representatives will make necessary upgrades at the railroad crossing to minimize potential conflicts between construction and rail activities.
<u>Local</u>: Kern County General Plan Circulation Element, Sec. 2.3.2 & 2.3.3	Establishes level of service (LOS) D or better as minimum acceptable standard on County roadways, and a LOS C on State or Federal Highways.
	<u>Consistent:</u> As reflected in Traffic and Transportation Table 2, the LOS along these designated roadways would remain below the LOS D threshold requirement.
Kern County Circulation Element	Addresses long-term planning goals and procedures for transportation infrastructure system quality: standards and procedures for air transportation: and transportation safety in Kern County.
	<u>Consistent:</u> The applicant will work with Kern County and Caltrans in determining necessary roadway improvements needed for the entrance into the project site, and to insure traffic safety during construction and operations of the BSEP.
	Kern County must assure protection of road right-of-way for efficient management of circulation. Goals 3: Protecting corridors for future transportation facilities is most important transportation planning activity in any high growth area Goal 4: To reserve right –of- way to meet future road needs that result from development allowed by land use plans.
	<u>Consistent:</u> The applicant will work with Kern County to insure necessary rights-of-way are dedicated to the County for implementation in the Circulation Element of the General Plan.

CONCLUSIONS

1. The project as proposed would comply with all applicable LORS related to traffic and transportation and would not significantly degrade the level of service on SR-14 or SR-58.

2. Because of the project’s distance from the nearest airport, no impact on the California City Municipal Airport Airspace would occur, and the project would not impact aviation safety.

3. Staff is proposing Condition of Certification **TRANS-2** which would require a mitigation plan to repair Neuralia Road and California City Boulevard if they are damaged by installation of the gas pipeline.

4. There would be no significant direct or cumulative traffic and transportation impact and therefore no environmental justice issues.

5. Staff is proposing Condition of Certification **TRANS-3** to ensure the necessary approvals for the proposed Union Pacific railroad crossing.

PROPOSED CONDITION OF CERTIFICATION

TRANS-1 Prior to the start of construction activities, the project owner shall complete the construction of the physical improvements at the SR-14 entrance into the project site.

Verification: At least 30 days prior to start of construction, the project owner shall in coordination with Caltrans, design and construct the roadway improvements described above to their satisfaction. The project owner shall notify the CPM that these roadway improvements have been completed and are ready for inspection.

TRANS-2 Prior to site mobilization activities, the project owner shall prepare a mitigation plan for Neuralia Road and California City Boulevard due to open cutting of the roadways for the installation of the gas pipeline. The intent of this plan is to ensure that if these roadways are disturbed by project construction, they will be repaired and reconstructed to original or as near original condition as possible. This plan shall include:

- Documentation of the pre-construction condition of Neuralia Road from the project site south to California City Boulevard and west on California City Boulevard to the SoCal gas tie-in point. Prior to the start of site mobilization, the project owner shall provide to the CPM photographs or videotape of gas line routes discussed above.
- Documentation of any portions of Neuralia Road and California City Boulevard that may be inadequate to accommodate oversize or large construction vehicles and identification of necessary remediation measures;
- Provision for appropriate bonding or other assurances to ensure that any damage to Neuralia Road and California City Boulevard, due to construction activity will be remedied by the project owner; and
- Reconstruction of portions of Neuralia Road and California City Boulevard that are damaged by project construction due to oversize or overweight construction vehicles.

Verification: At least 90 days prior to the start of site mobilization, the project owner shall submit a mitigation plan focused on restoring Neuralia Road and California City Boulevard to its pre-project condition to the city of Kern County and California City Public Works and Planning Department for review and comment and to the CPM for review and approval.

Within 90 days following the completion of construction, the project owner shall provide photo/videotape documentation to the Kern County and California City Public Works and Planning Department and the CPM that the damaged sections of Neuralia Road and California City Boulevard have been restored to their pre-project condition.

TRANS-3 Prior to start of construction, the project owner shall obtain approval from the California Public Utilities Commission (CPUC) to install railroad crossing improvements (gates and signals) to the Union Pacific /Lone Pine Branch track for access to the BSEP site. If the warning equipment is not installed prior to the start of site preparation or earth moving activities, then the project owner shall install temporary measures, including the stationing of flag persons, to the satisfaction of Union Pacific representatives and the CPUC. These temporary measures shall remain in place until the permanent equipment is installed.

Verification: The project owner shall inform Union Pacific Railroad, Kern County, California City, CPUC, and the CPM that the final grade crossing warning equipment (gates and signals) are ready for inspection.

REFERENCES

California City, 2008. California City Municipal Airport website- http:/www.calcityairport.com.

Caltrans. 2008. Traffic Volumes on California State Highways.

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Transportation Research Board. 2000. Highway Capacity Manual.

APPENDIX A

HIGHWAY CAPACITY MANUAL

The *Highway Capacity Manual* is prepared by the Transportation Research Board, Committee on Highway Capacity and Quality of Service. It represents a concentrated, multi-agency effort by the Transportation Research Board, the Federal Highway Administration, the American Association of Highway and Transportation Officials, and other traffic/transportation related agencies. It is the most widely used resource for traffic analysis. Several versions of the *Highway Capacity Manual* (*HCM*) have been published. The current edition was published in 2000. It contains concepts, guidelines, and procedures for computing the capacity and quality of service of various highway facilities, including freeways, signalized and unsignalized intersections, and rural highways, and the effects of transit, pedestrians, and bicycles on the performance of these systems.

LEVEL OF SERVICE

The description and procedures for calculating capacity and level of service are found in the *Highway Capacity Manual 2000*. The *Highway Capacity Manual 2000* represents the latest research on capacity and quality of service for transportation facilities.

Quality of service requires quantitative measures to characterize operational conditions within a traffic stream. Level of service (LOS) is a quality measure describing operational conditions within a traffic stream, generally in terms of such service measures as speed and travel time, freedom to maneuver, traffic interruptions, and comfort and convenience.

Six levels of service are defined for each type of facility that has analysis procedures available. Letters designate each level, from A to F, with level of service A representing the best operating conditions and level of service F, the worst. Each level of service represents a range of operating conditions and the driver’s perception of these conditions. Safety is not included in the measures that establish service levels. A general description of service levels for various types of facilities is shown in **Table A**.

Table A
Level of Service Description

Facility Type	Uninterrupted Flow	Interrupted Flow
	Freeways Multi-Lane Highways Two-Lane Highways Urban Streets	Signalized Intersections Unsignalized Intersections - Two-Way Stop Control - All-Way Stop Control
Level of Service		
A	Free-flow.	Very low delay
B	Stable flow. Presence of other users noticeable.	Low delay
C	Stable flow. Comfort and convenience starts to decline.	Acceptable delay
D	High density stable flow.	Tolerable delay
E	Unstable flow.	Limit of acceptable delay
F	Forced or breakdown flow.	Unacceptable delay

Source: *Highway Capacity Manual 2000*

Interrupted Flow

One of the more important elements limiting, and often interrupting, the flow of traffic on a highway is the intersection. Flow on an interrupted facility is usually dominated by points of fixed operation such as traffic signals and stop and yield signs. These all operate quite differently and have differing impacts on overall flow.

Signalized Intersections

The capacity of a highway is related primarily to the geometric characteristics of the facility, as well as to the composition of the traffic stream on the facility. Geometrics are a fixed, or non-varying, characteristic of a facility.

At the signalized intersection, an additional element is introduced into the concept of capacity: time allocation. A traffic signal essentially allocates time among conflicting traffic movements seeking use of the same physical space. The way in which time is allocated has a significant impact on the operation of the intersection and on the capacity of the intersection and its approaches.

Level of service for signalized intersections is defined in terms of control delay, which is a measure of driver discomfort, driver frustration, fuel consumption, and increased travel time. The delay experienced by a motorist is made up of a number of factors that relate to control, traffic, and incidents. Total delay is the difference between the travel time actually experienced and the reference travel time that would result during base conditions (that is, in the absence of traffic control, geometric delay, any incidents, and any other vehicles). Specifically, level of service criteria for traffic signals is stated in terms of average control delay per vehicle, typically for a 15-minute analysis period. Delay is a complex measure and depends on a number of variables, including the quality of progression, the cycle length, the ratio of green time to cycle length, and the volume to capacity ratio for the lane group.

For each intersection analyzed, the average control delay per vehicle per approach is determined for the peak hour. A weighted average of control delay per vehicle is then determined for the intersection. A level of service designation is given to the control delay to better describe the level of operation. Descriptions of levels of service for signalized intersections can be found in **Table B**.

Table B
Description of Level of Service for Signalized Intersections

Level of Service	Description
A	Very low control delay, up to 10 seconds per vehicle. Movement forward (progression) is extremely favorable, and most vehicles arrive during the green phase. Many vehicles do not stop at all. Short cycle lengths may tend to contribute to low delay values.
B	Control delay greater than 10 and up to 20 seconds per vehicle. There is good progression or short cycle lengths or both. More vehicles stop, causing higher levels of delay.
C	Control delay greater than 20 and up to 35 seconds per vehicle. Higher delays are caused by fair progression or longer cycle lengths or both. Individual cycle failures may begin to appear. Cycle failure occurs when a given green phase does not serve a waiting line of vehicles, and overflow occurs. The number of vehicles stopping is significant, though many still pass through the intersection without stopping.
D	Control delay greater than 35 and up to 55 seconds per vehicle. The influence of congestion becomes more noticeable. Longer delays may result from some combination of unfavorable progression, long cycle lengths, or high volumes. Many vehicles stop, the proportion of vehicles not stopping declines. Individual cycle failures are noticeable.
E	Control delay greater than 55 and up to 80 seconds per vehicle, the limit of acceptable delay. High delays usually indicate poor progression, long cycle lengths, and high volumes. Individual cycle failures are frequent.
F	Control delay in excess of 80 seconds per vehicle. Unacceptable to most drivers. Oversaturation and arrival flow rates exceed the capacity of the intersection. Many individual cycle failures. Poor progression and long cycle lengths may also be contributing factors to higher delay.

Source: *Highway Capacity Manual 2000*

The use of control delay, often referred to as signal delay, was introduced in the 1997 update to the *Highway Capacity Manual*. It represents a departure from previous updates. In the third edition of the *Highway Capacity Manual*, published in 1985 and the 1994 update to the third edition, delay only included stop delay. Thus, the level of service criteria listed in Table B differs from earlier criteria.

Unsignalized Intersections

The current procedures on unsignalized intersections were first introduced in the 1997 update to the *Highway Capacity Manual* and represent a revision of the methodology published in the 1994 update to the 1985 Highway Capacity Manual. The revised procedures use control delay as a measure of effectiveness to determine level of service. Delay is a measure of driver discomfort, driver frustration, fuel consumption, and increased travel time. The delay experienced by a motorist is made up of a number of factors that relate to control, traffic, and incidents. Total delay is the difference between the travel time actually experienced and the reference travel time that would result during base conditions (that is, in the absence of traffic control, geometric delay, any incidents, and any other vehicles). Control delay is the increased time of travel for a vehicle approaching and passing through an unsignalized intersection, compared with a free-flow vehicle if it were not required to slow or stop at the intersection.

Two-Way Stop Controlled Intersections

Two-way stop controlled intersections, in which stop signs are used to assign the right-of-way, are the most prevalent type of intersection in the United States. At two-way stop-controlled intersections, the stop-controlled approaches are referred to as the *minor street approaches* and can be either public streets or private driveways. The approaches that are not controlled by stop signs are referred to as the *major street approaches*.

The capacity of movements subject to delay is determined using the "critical gap" method of capacity analysis. Expected average control delay based on movement volume and movement capacity is calculated. A level of service designation is given to the expected control delay for each minor movement. Level of service is not defined for the intersection as a whole. Control delay is the increased time of travel for a vehicle approaching and passing through an all-way stop-controlled intersection, compared with a free-flow vehicle if it were not required to slow or stop at the intersection. A description of levels of service for two-way stop-controlled intersections is found in **Table C**.

Table C
Description of Level of Service for Two-Way Stop Controlled Intersections

Level of Service	Description
A	Very low control delay: less than 10 seconds per vehicle for each movement subject to delay.
B	Low control delay: greater than 10 and up to 15 seconds per vehicle for each movement subject to delay.
C	Acceptable control delay: greater than 15 and up to 25 seconds per vehicle for each movement subject to delay.
D	Tolerable control delay: greater than 25 and up to 35 seconds per vehicle for each movement subject to delay.
E	Limit of acceptable control delay: greater than 35 and up to 50 seconds per vehicle for each movement subject to delay.
F	Unacceptable control delay: in excess of 50 seconds per vehicle for each movement subject to delay.

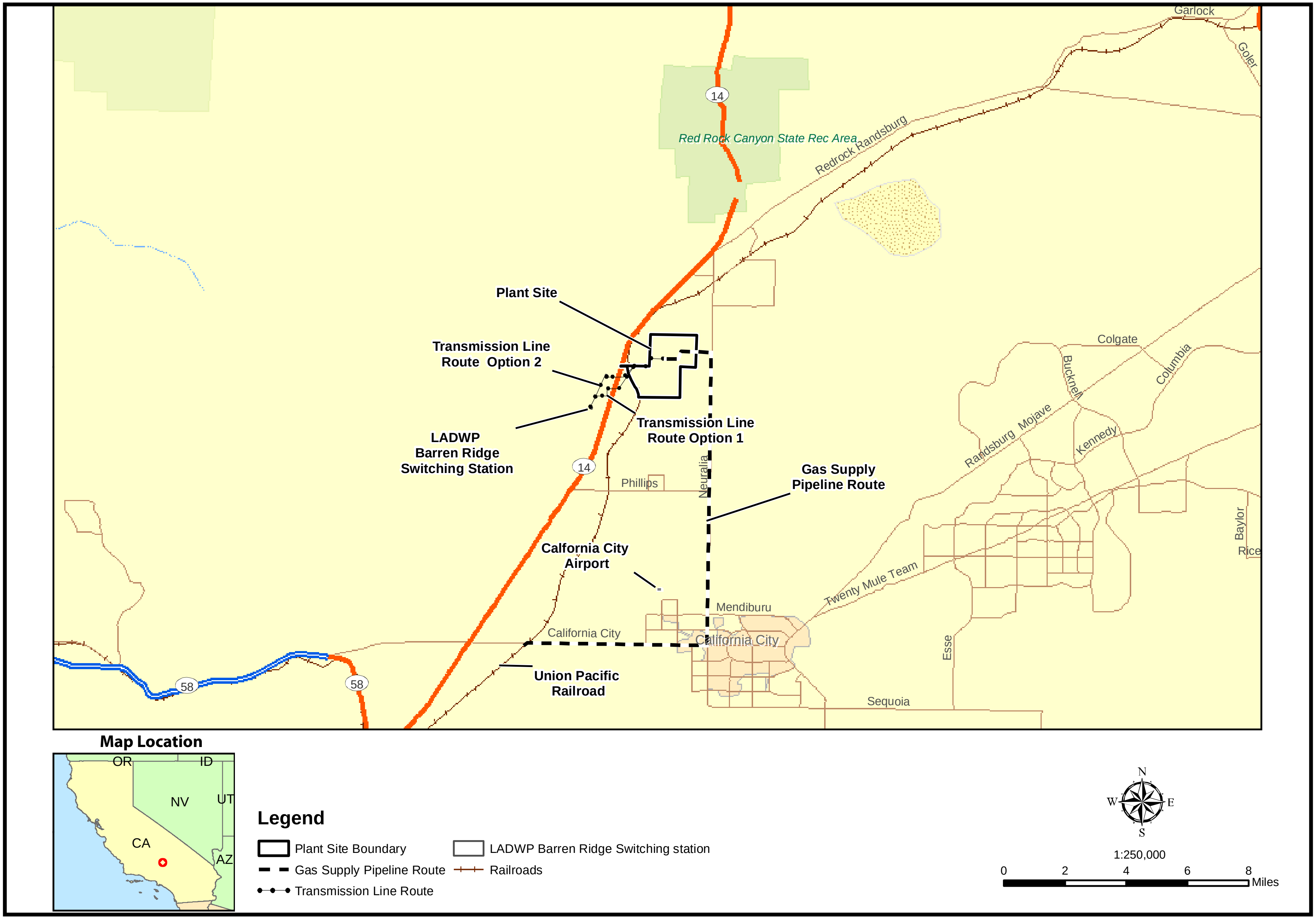
Source: *Highway Capacity Manual 2000*

REFERENCE

Transportation Research Board. *Highway Capacity Manual 2000*. Washington, D.C.

TRAFFIC AND TRANSPORTATION - FIGURE 1

Beacon Solar Energy Project - Regional Transportation Facilities

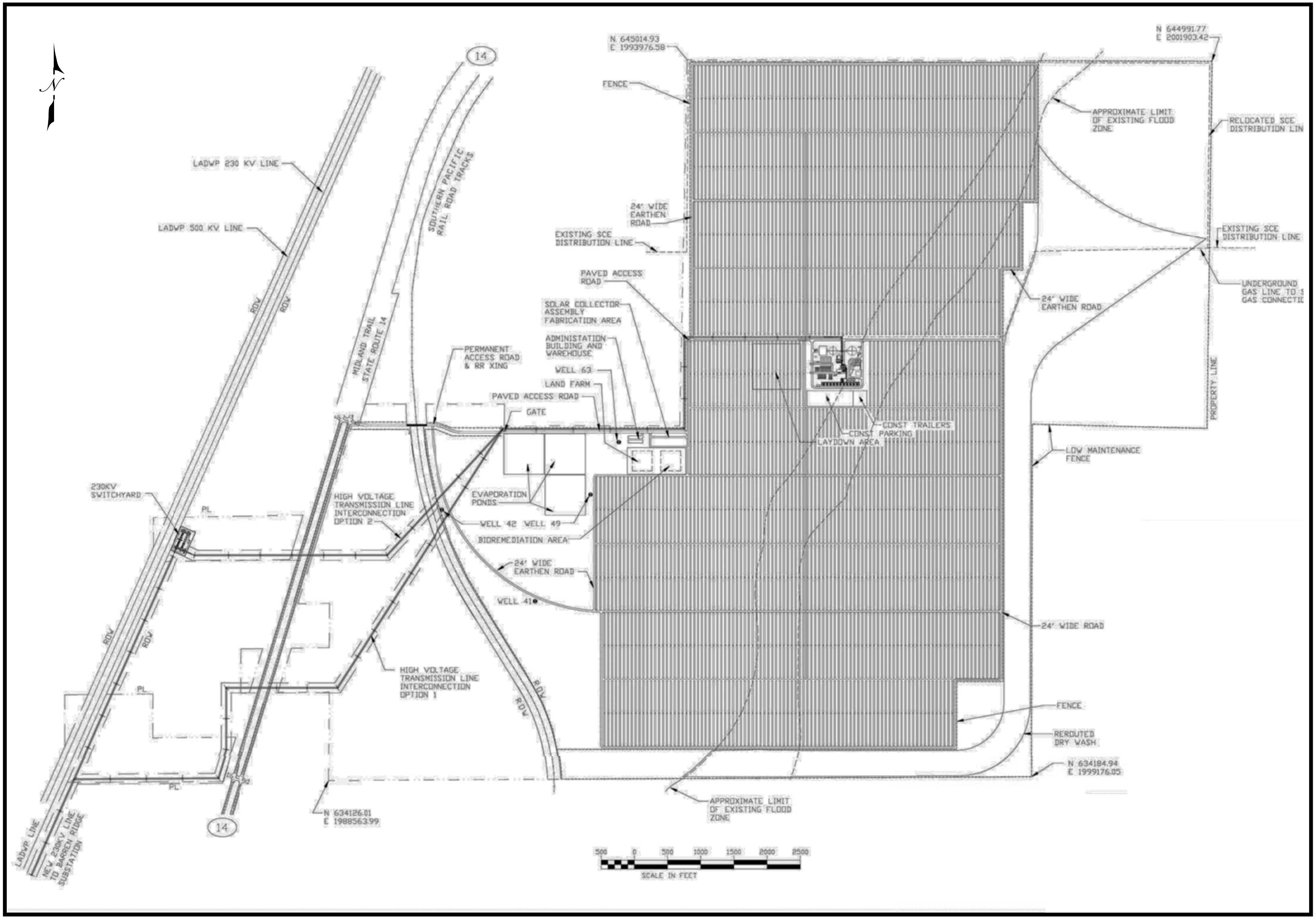


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMETAL PROTECTION DIVISION, APRIL 2009

SOURCE: 08-AFC-2 Figure 5.13-1

TRAFFIC AND TRANSPORTATION - FIGURE 2

Beacon Solar Energy Project - General Arrangement Site Plan



SOURCE: 08-AFC-2 Figure 2-4

TRANSMISSION LINE SAFETY AND NUISANCE

Obed Odoemelam, Ph.D.

SUMMARY OF CONCLUSIONS

The applicant, Beacon Solar, LLC (Beacon Solar) , proposes to transmit the power from the proposed Beacon Solar Energy Project (BSEP) to the Los Angeles Department of Water and Power's (LADWP's) transmission grid through LADWP's existing 230-kV Barren Ridge Switching Station approximately 1.5 miles southwest of the project site. The applicant proposes two similar options for this connecting overhead line to allow for flexibility in the ultimate choice of design and route. One option would involve the use of a line of approximately 3.5 miles, the other, would involve the use of a 2.3-mile line each of which would run from the project site to the interconnection points within the Barren Ridge Switching Station. Each candidate line would (a) be constructed according to LADWP's design guidelines for line safety and field management, (b) traverse undisturbed desert land with no nearby residents, thereby eliminating the potential for residential electric and magnetic field exposures and (c) be owned and operated by LADWP so its proposed design, erection, and maintenance plan would be according to standard LADWP practices, which conform to applicable laws, ordinances, regulations and standards (LORS). With the five proposed conditions of certification, any safety and nuisance impacts from each candidate line would be less than significant.

INTRODUCTION

The purpose of this analysis is to assess the line design and operational plan for the proposed Beacon Solar Energy Project's two candidate overhead transmission lines to determine whether their related field and non-field impacts would constitute a significant environmental hazard in the area around the proposed routes. All related health and safety 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 following federal, state, and local laws and policies apply to the control of the field and non-field impacts of electric power lines. Staff's analysis examines the project's compliance with these requirements.

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 70/460-1G, "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.
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.

Applicable LORS	Description
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

As noted in the **Project Description** section, the site for the proposed BSEP is a 2,012-acre parcel in unincorporated Kern County, California, at the western edge of the Mojave Desert, approximately 15 miles north of the town of Mojave. The site is largely vacant and significantly disturbed from agricultural activities of the mid-1980s. There are several abandoned structures but no nearby residences. The nearest is approximately 0.3 miles from the project's property boundaries. At the western boundary of the proposed project site are two LADWP transmission lines sharing the same 250-foot north-south LDWP right-of –way. One of them is the 500-kV Celilo-Sylmar direct current (DC) line; the other is the Inyo-Barren Ridge 230-kV alternating current (AC) line. The Barren Ridge switching station to be interconnected is approximately 1.5 miles southwest of the southwest corner of the proposed project site. LADWP designed the Barren Ridge switching station to accommodate transmission of power from additional renewable power projects in the area and would therefore be able to handle the power from the proposed BSEP with minimal modification. Construction of BSEP would involve rerouting of an existing Southern California Edison (SCE) distribution line running east-west across the northern portion of the project site (Beacon Solar 2008 pp 2-29 through 2-32).

PROJECT DESCRIPTION

Only one of two candidate transmission lines would be built for the proposed power transmission. The first option would consist of the segments listed below:

- A new, approximately 3.5-mile 230-kV, single-circuit, overhead transmission line approximately 1.6 miles of which would lie within the 2,012-acre project site and running west from the power generators and south across private property to the Barren Ridge switching station.
- The project's on-site 230-kV switchyard from which the conductors would extend to the connection points at the Barren Ridge station; and
- Project-related modifications within the Barren Ridge switching station.

The second option would consist of the following segments:

- A new, approximately 2.3-mile 230-kV,single-circuit, overhead transmission line approximately 1.6 miles of which would lie within the project's property boundaries as it runs west from the power generators to a new project switching station to be located where the project's transmission line first meets LADWP's existing transmission line right-of-way;
- A second 230-kV transmission line slightly over one mile long and constructed east of, and adjacent to the existing LADWP line right-of-way from which it would run from the new project switching station to the Barren Ridge switching station;
- The project's on-site 230-kV switchyard; and
- Project-related modifications at the Barren Ridge switching station.

The lines for either option would be erected on mono-pole steel/concrete structures of a minimum of 79 feet and a maximum of 110 feet as typical of similar LADWP lines. Since the total lengths would be similar for each option, a total of 36 of such poles would be used no matter which is chosen. Since the chosen line would be connected to the LADWP power system, its conductors would be standard low-corona aluminum, steel-reinforced cables utilized by LADWP for lines in this voltage class. The applied design and construction would be in keeping with LADWP guidelines that ensure line safety and efficiency together with reliability, and maintainability (Beacon Solar 2008 pp 2-30, and 5.14-1 through 5.14-12).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHODS AND THRESHOLDS FOR DETERMINING SIGNIFICANCE

The potential magnitude of the line impacts of concern in this staff analysis depends on compliance with the listed design-related LORS and industry standards. These LORS 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.

DIRECT IMPACTS AND MITIGATION

Aviation Safety

Any potential hazard to area aircraft would relate to the potential for collision in the navigable airspace.

As noted by the applicant (Beacon Solar 2008 p 5.14-6), the nearest airport to the project and related facilities is the California City Municipal Airport approximately 6 miles to the south and thus too far away for the line's structures to pose a collision hazard to area aircraft according to FAA criteria. The Edwards Air Force Base is located approximately 20 miles to the southwest placing it beyond the zone of potential collision hazard to any of its aircraft. While the FAA would thus, not require a "Notice of Proposed Construction and Alteration (Form 7040), the applicant intends to file this form for FAA's information as common within the industry.

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 chosen line option would be built and maintained in keeping with standard LADWP 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 options. The proposed low-corona designs are used for all LADWP lines of similar voltage rating to reduce surface-field strengths and the related potential for corona effects. Since these existing lines do not currently cause corona-related complaints along their existing routes, and there are no residences in the vicinity of either of the proposed routes, staff does not expect any residential corona-related radio-frequency interference or related complaints in the general project area. However, staff recommends Condition of Certification **TLSN-2** to ensure mitigation as required by the FCC in the unlikely event of complaints.

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 BSEP. 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. 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 line 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 LADWP lines would be implemented for the proposed project line). 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-4** is recommended to ensure compliance with important aspects of the fire prevention measures (Beacon Solar 2008, pp 5.14-5 and 5.14-11).

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 (Beacon Solar 2008 pp 5.14-7 through 5.14-11) 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. This would be accomplished through standard industry grounding practices (Beacon Solar 2008, p 5.14-8). Staff recommends Condition of Certification **TLSN-5** to ensure such grounding for BSEP.

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 CPUC, other regulatory agencies, and staff have evaluated the available evidence and concluded that such fields do not 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

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.

In keeping with this CPUC policy, staff requires a showing that each proposed overhead line would be designed according to the 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 most new lines in California are currently required by the CPUC to be designed according to the EMF-reducing guidelines of the electric utility in the service area involved, the proposed line’s fields are required under this CPUC policy to be similar to fields from similar lines in that service area. Designing the chosen line according to existing LADWP field strength-reducing guidelines would constitute compliance with the CPUC requirements for line field management.

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 CPUC found that there is no 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 are 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. Given the potential for human exposures, staff recommends measurements of each line's maximum fields to allow for uniform, field strength-related characterization of all lines. It is such field strength measurements that are required in Condition of Certification **TLSN-3**.

Industry'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 too 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 exposure 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 LADWP lines, specific field strength-reducing measures would be incorporated into the design of the proposed line 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.

The applicant has estimated the maximum field strengths typically encountered along the route of either line option at a benchmark distance of 75 feet from the centerline, which would mark the edge of the 150-foot right-of-way. For the electric field, this maximum intensity was estimated as 0.2 kV/m, and 15 mG for the companion magnetic field. Staff has verified the accuracy of the applicant's assumptions for lines in this voltage class but recommends the on-site measurement requirements in Condition of Certification **TLSN-3** to validate the applicant's assumed reduction efficiency. These field intensities are similar to those of LADWP lines of similar voltage and current-carrying intensity.

CUMULATIVE IMPACTS AND MITIGATION

When field intensities are measured or estimated 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. As noted by the applicant (Beacon Solar 2008, pp 5.14-9 and 5.7-11 and 5.712), the conductors for either line option would be located in a new right-of- way away from the field impact zones for other area lines, eliminating the interactive and therefore, cumulative effects of fields from existing area lines. The transmission lines from approved or reasonably foreseeable future area solar and non-solar projects (the Pine Tree Wind Development Project, the LADWP Barren Ridge-Castaic Project, the Opti-Solar Sapphire Project, the Opti-Solar Turquoise Project, the Solar Millennium-Ridgecrest Project and Solar Millennium Project) would not be located close enough to the proposed line options for cumulative field impacts of potential significance (Beacon Solar 2008, p 5.1-1 through 5.1-4). Since the chosen project transmission line option and related switchyard would be designed according to applicable field-reducing LADWP guidelines (as currently required by the CPUC for effective field management), any contribution to total area exposures should be at levels expected for LADWP 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 would be assessed from the results of the field strength measurements specified in Condition of Certification **TLSN-3**.

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 this case is LADWP. Since either of the proposed line options and related switchyard would be designed according to the respective requirements of the LORS listed in Table 1, and operated and maintained according to current LADWP guidelines on line safety and field strength management, staff considers the presented design and operational plans to be in compliance with the health and safety requirements of concern in this analysis and recommends approval of both options, leaving it up to the applicant to ultimately chose the preferred one. The actual contribution of the chosen line to the area’s field exposure levels would be assessed from results of the field strength measurements required in Condition of Certification **TLSN-3**.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff received no public or agency comments on the transmission line nuisance and safety aspects of the proposed BSEP.

CONCLUSIONS

Since neither of the proposed line options poses an aviation hazard according to current FAA criteria, staff does not consider it necessary to recommend location changes on the basis of a potential hazard to area aviation.

The potential for nuisance shocks from either line option would be minimized through grounding and other field-reducing measures to be implemented in keeping with current LADWP 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 PUC'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 proposed route.

Since electric or magnetic field health effects have neither been established nor ruled out for fields from the proposed BESP line options 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 designs and operational plans would be adequate to ensure that the electric and magnetic fields from either line 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 either option given the general absence of residences along their proposed routes. On-site worker or public exposure would be short term and at levels expected for LADWP 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 either of the proposed line options would be operated to minimize the health, safety, and nuisance impacts of concern to staff and would be located along a route without nearby residences, staff considers the proposed design, maintenance, and construction plans as complying with the applicable laws. With the conditions of certification proposed below, any such impacts would be less than significant for either option.

PROPOSED CONDITIONS OF CERTIFICATION

TLSN-1 The project owner shall construct the chosen transmission line option 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 Los Angeles Department of Water and Power's EMF-reduction guidelines.

Verification: At least thirty days before starting construction of the chosen line option 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 line will be constructed according to the requirements stated in the condition.

TLSN-2 The project owner shall ensure that every reasonable effort will be made to identify and correct, on a case-specific basis, any complaints of interference with radio or television signals from operation of the chosen line option or associated switchyard.

Verification: At least thirty days before starting operation of either line option, the project owner shall submit to the CPM a letter signed by a California registered electrical engineer affirming the project owner's intention to comply with this requirement.

TLSN-3 The project owner shall use a qualified individual to measure the strengths of the electric and magnetic fields from the constructed line at the points of maximum intensity for which intensity estimates were provided by the applicant. 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 not 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-4 The project owner shall ensure that the rights-of-way of the chosen transmission line option are 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: At least thirty days before the start of operations, the project owner shall transmit to the CPM a letter affirming the project owner's intention to comply with this condition.

TLSN-5 The project owner shall ensure that all permanent metallic objects within the right-of-way of the constructed project line are grounded according to industry standards regardless of ownership.

Verification: At least 30 days before the lines are energized, the project owner shall transmit to the CPM a letter affirming the intention to comply with this condition.

REFERENCES

Electric Power Research Institute (EPRI) 1982. Transmission Line Reference Book: 345 kV and Above.

Beacon Solar Energy Project. Application for Certification (08-AFC-2) of CPV Sentinel Energy project, Volumes I and II submitted to the California Energy Commission on June 25, 2007.

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.

Visual Resources

Mark R. Hamblin

SUMMARY OF CONCLUSIONS

The proposed Beacon Solar Energy Project would be seen from elevated locations in the northern Fremont Valley. The introduction of the project would change the existing physical setting of the Fremont Valley floor from a moderately disturbed desert floor landscape to a highly human-altered landscape; principally due to 1,244 acres of the project site being covered with parabolic trough solar collectors. In addition, the introduction of the radiance from the parabolic trough arrays during operation would be prominent from elevated locations. Staff concludes the project would introduce a substantial significant “Aesthetic” impact under the California Environmental Quality Act and Guidelines at two selected key observation points (KOPs) that would be unmitigable. The KOP 2 location is from the U.S. Bureau of Land Management’s Jawbone Canyon Off Highway Vehicle (OHV) Open Area Ridgecrest Office, and the KOP 6 location is from the public hiking trail to Chuckwalla Mountain (5,036 foot elevation) in the Piute Mountain Range, approximately two miles west of the project site. See KOP 2 and KOP 6 discussion under section **C. Visual Character or Quality**.

If the Energy Commission approves the project, staff has recommended conditions of certification for the project to minimize impacts under the California Environmental Quality Act and Guidelines to the greatest extent possible, and to comply with applicable laws, ordinances, regulations, and standards pertaining to aesthetics or preservation and protection of sensitive visual resources.

INTRODUCTION

Visual resources are the viewable natural and human-made features of the environment. In this section, staff evaluates the proposed project’s construction and operation. Staff uses the criteria in the “Aesthetic” section of Appendix G in the California Environmental Quality Act (CEQA) Guidelines to determine if the project would introduce a significant impact under CEQA. Staff also determines whether the project would comply with applicable laws, ordinances, regulations, and standards (LORS) pertaining to aesthetics, or preservation and protection of sensitive visual resources.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Visual Resources Table 1 provides a general description of identified adopted federal, state, and local LORS pertaining to aesthetics, or preservation and protection of sensitive visual resources relevant to the proposed project.

Visual Resources Table 1
Laws, Ordinances, Regulations, and Standards

Applicable LORS	Description
Federal	
Transportation Equity Act for the 21st Century of 1998, and Safe, Accountable, Flexible, and Efficient Transportation Equity Act of 2005.	The project site does not involve federal managed lands, nor a recognized National Scenic Byway or All-American Road within its vicinity.
State	
California Streets and Highways Code, Sections 260 through 263 – Scenic Highways	Ensures the protection of highway corridors that reflect the State's natural scenic beauty.
Local	
Kern County General Plan, adopted March 13, 2007	
Land Use, Open Space, and Conservation Element (adopted April 15, 1982) Chapter 1 - General Provisions - Section 1.10.7 Light and Glare	Light and glare from discretionary new development projects are to be minimized in rural as well as urban areas. Encourages the use of low-glare lighting to minimize nighttime glare effects on neighboring properties.
Chapter 2 – Circulation Element - Section 2.3.9 Scenic Route Corridors	A scenic route must be officially set as a Scenic Route by the Kern County Board of Supervisors, or the State of California.
Chapter 5 – Energy Element - Section 5.4.5 Solar Energy Development	Encourages solar energy development in the desert and valley planning regions previously disturbed that does not pose significant environmental, public health and safety hazards.
- Section 5.4.7 Transmission Lines	Discourages the siting of above-ground transmission lines in visually sensitive areas.

Applicable LORS	Description
Kern County Code *Title 19 Zoning*	
Chapter 19.12 - Exclusive Agriculture	
- Section 19.12.070 – Yard and Setbacks	Provides yard and setback requirements.
- Section 19.12.080 – Height Limits	There is no height limit on nonresidential structures, except in areas of protected military airspace.
- Section 19.12.110 – Signs	Identifies permitted signs.
- Section 19.12.120 – Landscaping	No landscaping is required in the Exclusive Agriculture district, except where the proposed use is subject to a plot plan review.

SETTING

The proposed Beacon Solar Energy Project (BSEP) would be built along the western edge of the northern Fremont Valley, approximately four miles north-north west of California City, in Kern County, California (**Visual Resources Figure 1** – Aerial View of Beacon Solar Energy Project and Vicinity).

The Fremont Valley is a slightly elongated valley surrounded by mountains. The Piute Mountains are to the west, the El Paso Mountains are to the north and the Rand Mountains to the east. Koehn Lake, a dry lake bed is to the east-northeast, and the larger portion of the Mojave Desert is to the southeast.

The proposed BSEP site would occupy approximately 2,012 acres of valley floor. The terrain is relatively flat with a gentle slope of one to three percent to the northwest. The valley floor is typified by clay and gravelly loamy sand, ruderal vegetation, creosote bush scrub with patches of desert saltbush scrub, and desert wash scrub. The site is undeveloped except for a grouping of abandoned and deteriorating structures that served the Fremont Valley Ranch. Pine Tree Creek, a dry desert wash crosses near the center of the site.

The settlement of Rancho Seco is approximately ½-mile north of the proposed project site. Honda Proving Center of California is ½-mile east. The Proving Center has a 7.5 mile oval track, as well as a five-mile winding road course that are used primarily for testing Honda and Acura automobiles and motorcycles.

There are identified recreational areas within five miles of the project site. Jawbone Canyon provides hundreds of miles of trail riding opportunities available in this region and outside of the federal Bureau of Land Management, Off Highway Vehicle (OHV)

Area. The Jawbone OHV Open Area, north-northeast of the project site, offers over 7,000 acres of open-use public land where individuals can ride. The entire OHV area and surrounding public lands are open to primitive camping. Most of the sites within the OHV area are accessible by two-wheel drive vehicles with trailers.

Red Rock Canyon State Park, approximately 16,600 acres, is located where the southernmost tip of the Sierra Nevada converges with the El Paso Range, north of the project site. It features scenic desert cliffs, buttes and spectacular rock formations. Miles of trails meander through the park. Horses are allowed on all trails in the park. Street legal vehicles and OHV may travel on a dirt road system within the park.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

The California Environmental Quality Act defines a “significant effect on the environment” to mean a “substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project including . . . objects of historic or aesthetic significance” (California Code of Regulations, Title 14, Section 15382).

To determine whether there is a potentially significant visual resources impact generated by a project, Energy Commission staff reviews the project using the CEQA Guidelines Appendix G Environmental Checklist pertaining to “Aesthetics”. The checklist questions include the following:

A. Would the project have a substantial adverse effect on a scenic vista?

B. Would the project substantially damage scenic resources, including, but not limited to trees, rock outcroppings, and historic buildings within a state scenic highway?

C. Would the project substantially degrade the existing visual character or quality of the site and its surroundings?

D. Would the project create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?

DIRECT/INDIRECT IMPACTS AND MITIGATION

The impact discussion is presented under the following CEQA headings: scenic vista, scenic resources, visual character or quality, and light or glare.

A. SCENIC VISTA

“Would the project have a substantial adverse effect on a scenic vista?”

There is no national, state, or county designated scenic vista in the project vicinity; therefore, the project would not cause a significant impact under this criterion. Staff discusses under **C. Visual Character or Quality** (below) the visual impact from selective KOPs. The introduction of the project would change the valley floor from a moderately disturbed desert floor landscape to a highly human-altered landscape;

principally due to 1,244 acres of the project site being covered with parabolic trough solar collectors. Also, the introduction of the radiance from the parabolic trough arrays during operation would be prominent from elevated locations.

B. SCENIC RESOURCES

"Would the project substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway corridor?"

A scenic resource for the purpose of this analysis includes a unique water feature (waterfall, transitional water, part of a stream or river, estuary); a unique physical geological terrain feature (rock masses, outcroppings, layers or spires); a tree having a unique visual/historical importance to a community (a tree linked to a famous event or person, an ancient old growth tree); historic building; or a designated federal scenic byway or state scenic highway corridor. There are no identified scenic resources on the project site.

SR-14 is not listed by the California Department of Transportation (Caltrans) as a state scenic highway. The County of Kern has not designated SR-14 a county scenic highway.

Thus, the project would not cause a significant impact under this criterion.

C. VISUAL CHARACTER OR QUALITY

"Would the project substantially degrade the existing visual character or quality of the site and its surroundings?"

PROJECT SITE

The proposed 2,012-acre project site to be used for the BSEP consists of desert loamy sand, ruderal vegetation, areas colonized with desert saltbush, and a compound of twelve deteriorating buildings and mobile homes that served the former farm operation (**Visual Resources Figure 2** - Existing View of the Project Site).

The proposed BSEP's most publicly visible structures have been identified in **Visual Resources Table 2** (**Visual Resources Figure 3** – General Arrangement Site Plan).

VISUAL RESOURCES Table 2
Summary of Major Publicly Visible Structures

Project Component	Number of Units	Length, Width, Diameter (approximately)	Height (approximately)	Color and Materials
Transmission Line Steel Pole, In-Line (over-crossing of railroad track and SR-14)	4	8-foot diameter	110 feet	corrugated steel, concrete
Transmission Line Steel Pole, In-Line	32	8-foot diameter	79 feet	corrugated steel, concrete
Steam Turbine Generator Enclosure	1	144-foot x 45-foot	55 feet	corrugated steel
Power Block Control Room	1	120-foot x 100-foot	50 feet	—
Warehouse	1	70-foot x 75-foot	50 feet	—
Deaerator/Storage Tank	1	24-foot x 8-foot diameter	50 feet	—
Cooling Tower	1	595-foot x 55-foot (11-cell)	45 feet	—
Take-off, Dead-end and Bus Structures*	4	35-foot x 30-foot	40 feet	corrugated steel
Raw Water Storage Tank	1	120-foot diameter (2,840,000 gallon)	36 feet	steel
Administration Building	1	270-foot x 45-foot	35 feet	—
SCA Fabrication Building	1	550-foot x 127-foot	35 feet	—
Treated Water Storage Tank	1	136-foot diameter (2,350,000 gallon)	34 feet	steel
HTF Surge Volume Expansion Tank	6	70-foot x 14-foot diameter	25 feet	—
Parabolic Trough	1,244 acres	492-foot x 19-foot	17-22 feet	steel, coated silver or polished aluminum, glass

*****final transmission structure design including tangent, angle, dead end, and pull-off structures and associated hardware are to be determined during the final engineering of the proposed interconnection (BSEP 2008a, pg. 2-29).
Source: BSEP 2008a, pg. 2-4-2-10, pg. 2-24-32, and pg. 5.15-9, Figure 2-1.

The BSEP proposes 1,244 acres of parabolic trough solar collectors aligned on a north-south axis. **Visual Resources Figure 4** provides photographs of the parabolic troughs at the Solar Electricity Generating Systems (SEGS) Kramer Junction project to illustrate the potential physical appearance of development on the BSEP site. The SEGS Kramer Junction project is approximately 35 miles south of the BSEP site, near Kramer Junction, California. The Kramer Junction project has been in operation since 1985. It has a generating capacity of 354 megawatts.

Project Viewshed

The applicant has prepared a computer generated map which shows the area within which the project could potentially be seen (**Visual Resources Figure 5** - Regional Visibility of BSEP). The map, typically, takes into account the visibility of the proposed project's most publicly visible structures on the project site, existing development, and other variables affecting potential visibility of the project that include: orientation of the viewer, duration of view, atmospheric conditions, lighting (daylight versus nighttime), and visual absorption capability. Visual absorption capability is defined as the extent to which the complexity of the landscape can absorb new elements without changing the overall visual character of the area. The furthest distance at which potentially significant visual impacts could occur from the project site is five miles.

Overall, the BSEP site would have a high visibility to several nearby residents and roadway users within 0.5 mile (*foreground view*), within 1.0 mile (*middleground view*), and other locations within the valley and surrounding mountains, 3.5 to 5.0 miles and beyond (*background view*). Beyond five miles, the BSEP would be either not visible due to topography, natural and/or human-made screening, or of such a small size in the background that it would hardly be noticeable[1].

There are approximately 40 residences within two miles of the project site. A number of the residences have a direct view of the project site (**Visual Resources Figure 6** – View of Existing Residences North of Project Site (Rancho Seco), **Visual Resources Figure 7** – View of Closest Residence West of Project Site along SR-14, **Visual Resources Figure 8** – View Towards the Honda Proving Center Oval Track from its Entrance and View from 1.5 Miles South of the Proving Center Entrance).

The project site would be visible from elevated locations within a federal and state identified recreational area closest to the project site. The Jawbone OHV Open Area and Red Rock Canyon State Park closest borders are approximately five miles from the project site. Jawbone OHV Open Area is to the north-northeast of the project site. It

[1] The Visual Management System of the U.S. Forrest Service uses distance zones. Distance zones are divisions of a particular landscape being viewed. The three distance zones are foreground, middleground, and background. Foreground – the limit of this zone is based upon distances at which details can be perceived. It will usually be limited to areas within ¼ to ½ mile of the observer, but must be determined on a case-by-case basis as should any distance zoning. Middleground - this zone extends from foreground zone to 3 to 5 miles from the observer. Background – this zone extends from middleground to infinity. Beyond five miles the project would be either not visible due to topography, natural and/or man-made screening, or of such a small size in the background that it would not be noticeable.

offers over 7,000 acres of open-use public land where camping and trail riding occur. Red Rock Canyon State Park to the north of the project site offers 16,600 acres for OHV and equestrian use, and hiking.

Motorists on State Route (SR) 14 would have an unobstructed view of the BSEP site. Caltrans 2007 traffic count information shows the annual average daily trips along SR-14 at Randsburg Cutoff/California City Boulevard, approximately 10 miles southeast of the project site, were 6,800 north bound trips and 9,800 south bound trips.

Key Observation Point Viewshed Evaluation

A “Key Observation Point” (KOP) is selected to be representative of the most critical viewsheds from off-site locations where the project would be visible to the public — for example; recreational and residential areas, travel routes, bodies of water, as well as scenic and historic resources. Because it is not feasible to analyze all the views in which a proposed project would be seen, it is necessary to select a KOP that would most clearly display the visual effects of the proposed project. A KOP may also represent a primary viewer group(s) that would potentially be affected by the project. Staff participates with the applicant in the selection of KOPs.

Staff evaluates the existing physical environmental setting, the KOP, and the visual change created by the proposed project to the viewshed.

The applicant has provided KOP photographs that show the existing physical condition without the project, and has prepared photographic simulations to show how the proposed project would appear in the existing condition. **Visual Resources Figure 9** shows the locations of the six KOPs used for this analysis:

- KOP 1 – Chollo Street, North of East Quartz Road Looking South;
- KOP 2 – Jawbone Canyon OHV Open Area Ridgecrest Field Office Looking South;
- KOP 3 – Front Area From Closest Residence West of Project Site Looking East;
- KOP 4 - Northbound State Route 14, Approximately Two Miles South of Project Site Looking Northeast; and
- KOP 5 – Southbound State Route 14, East of the Project Site, Looking South; and
- KOP 6 – Chuckwalla Mountain Hiking Trail Looking East.

Staff has provided in Appendix VR-1 a list of visual related terms defined by staff that has been used in the KOP analysis.

The project owner provided a discussion, photograph and simulation for a KOP 7 (SR-14 Southbound in Red Rock Canyon State Park) and KOP 8 (El Paso Mountain Ridgeline Trail in Red Rock Canyon State Park) in the Application for Certification (AFC). Staff reviewed the KOP 7 and KOP 8 information. KOP 7 is approximately five miles from the project site boundary and KOP 8 is approximately seven miles from the site. Staff did not include KOP 7 and KOP 8 as part of this analysis. A distance of five miles from a project site is generally considered the furthest distance at which potentially significant visual impacts could occur.

KOP 1 – Chollo Street, North of East Quartz Road Looking South

Visual Resources Figure 10 represents the existing view toward the project site from Chollo Street, approximately 400 feet north of East Quartz Road in Rancho Seco and one-mile northeast of the project site. The KOP represents a view from the 15-20 single family residences to the project site in Rancho Seco.

Visual Sensitivity

The observable KOP 1 physical landscape includes open space (landscape that is not filled with trees or topographic features) consisting of sand, ruderal vegetation and creosote bush scrub. In the background is a view of the Fremont Valley Ranch farm buildings. A portion of the Piute Mountains is also in view. The estimated public appeal of the visual impression (quality) of the KOP 1 view is considered to be moderate.

Viewers at this KOP location would mainly consist of residents who live in Rancho Seco. Residential viewers in general are considered to have a higher level of viewer concern (sensitivity), due to a concern for protecting their place of residence and extended duration (high) of viewing time. Viewer concern is considered moderately high. From this KOP, the viewer would experience an unobstructed view of the project site (high visibility) and have a long duration (high) view of the project site. Staff used a conservative estimate of between 20 to 30 residences within the Rancho Seco for the purposes of this KOP analysis. This number of viewers is considered moderate. Overall viewer exposure is considered moderately high.

The visual sensitivity (existing view without project) at KOP 1 is considered to be moderately high.

Visual Change

Visual Resources Figure 11a is a simulation of the proposed project's publicly visible structures after the completion of construction with transmission option one. **Visual Resources Figure 11b** represents the project's publicly visible structures with transmission option two.

As shown, the project's notable publicly visible structures would be the thirty-two 75-foot tall and four 110-foot tall steel monopoles (transmission line poles), and the 15-20 foot tall parabolic trough solar collectors.

The proposed visible structures in the power block would be a neutral color and have a non-reflective surface treatment. The applicant does not propose perimeter landscaping for the project site.

The degree of contrast (form, line, color, and texture) introduced by project structures would be moderate; meaning the contrast begins to attract attention and begins to dominate the characteristic landscape.

The simulation shows that the proportionate size relationship of project structures to other existing human-made and natural components would be codominant (moderate) in the total field-of-view. Project structures would not block the view of the mountains or sky in the KOP 1 view.

Staff notes that the simulation of KOP 1 does not clearly depict the portion of the solar collector field nearest the KOP viewer or Rancho Seco. The indistinct texture and uniform color in the simulation may understate the contrast that would be experienced by viewers. Color contrast could be strong if a neutral paint color is not used. Staff has recommended Condition of Certification **VIS-1** to provide for the project surface structure's use of neutral colors and non-reflective surface treatments.

The overall visual change caused by the introduction of the proposed project's structures into the view is considered to be moderate as a result of a moderate visual contrast, moderate visual scale, and low view blockage.

Staff concludes the introduction of proposed project's publicly visible structures would create a substantial visual impact that would be mitigated to a less than significant impact at KOP 1 with the effective implementation of Condition of Certification **VIS-1**.

KOP 2 – Jawbone Canyon OHV Open Area Ridgecrest Office Looking South
Visual Resources Figure 12 represents the existing view toward the project site from the public parking area of the U.S. Bureau of Land Management's Jawbone Canyon OHV Open Area Ridgecrest Office along SR-14, approximately three miles north of the project.

Visual Sensitivity

The observable KOP 2 physical landscape consists of ruderal vegetation and creosote bush scrub, a portion of Jawbone Canyon Road and State Route 14. Property fencing and a line of wooden utility poles are seen. In the middleground and background views is the open expanse of the Fremont Valley. SR-14 is not identified as a State Scenic Highway on the California Scenic Highway Mapping System, or as a county scenic highway according to the Kern County General Plan. The estimated public appeal of the visual quality of the KOP 2 view is considered to be moderate.

Viewers at this KOP location would mainly consist of motorists on SR-14 and recreationist who use Jawbone Canyon. The type of motorist would be defined as freeway travelers. Along this segment of SR-14, these users of the freeway system would generally be engaged in long distance travel, and travel at normal freeway speeds whose focus of attention is on long range non-peripheral views. They have a low to moderate sensitivity to the visual environment.

Viewers who use public recreational facilities (e.g. parks) have a high sensitivity to the visual environment when engaged in passive recreation, or quiet recreation such as bird watching and hiking, and have a moderate sensitivity when concentrating on more active recreation (e.g.; off-highway vehicle use).

Caltrans 2007 traffic count information shows the annual average daily trips (AADT) along SR-14 at Redrock Randsburg Road at SR-14, approximately four miles north of the project site, were 6,700 north bound trips and 6,600 south bound trips. This number of potential exposures of the project site is considered moderate to high.

From this KOP, freeway travelers, recreationists and visitors to the BLM Ridgecrest Field Office at the KOP 2 location would have an unobstructed, long duration view of the project site. The viewer would be accustomed to an unobstructed view of the valley floor and the project site. There is no scenic focal point or unique feature in the view that draws the viewer's eye. Overall viewer exposure is considered moderately high.

The visual sensitivity at KOP 2 is considered to be moderately high.

Visual Change

Visual Resources Figure 13a is a simulation of the proposed project's publicly visible structures after the completion of construction with transmission option one. **Visual Resources Figure 13b** represents the project's publicly visible structures with transmission option two.

Publicly visible project structures would include the parabolic troughs. Power block structures, the administration building and warehouse, and transmission lines poles are not visually discernable in the simulation. The approximate 1,250 acres of parabolic troughs would alter the texture of the existing desert floor. The contrast introduced by the parabolic troughs at operation when reflection of light is present accentuating the contrast with the surrounding landscape would be strong (high). The contrast demands attention, would not be overlooked and would be dominant in the landscape from this KOP.

The simulation shows that the proportionate size relationship of the publicly visible project structures to other existing human-made and natural components would be dominant (high) in the total field-of-view. Project structures would not block the view of mountains, sky, or valley floor from KOP 2.

The overall visual change caused by the introduction of the proposed project's structures into the view is considered to be high as a result of a high visual contrast, high visual scale, and low view blockage.

When considering the moderately high overall visual sensitivity and the high overall visual change, the introduction of the proposed publicly visible structures would introduce a substantial visual impact at this KOP. No available mitigation measures have been identified by staff to reduce the impact to a less than significant at this KOP.

KOP 3 – Front Area of Closest Residence West of Project Site Looking East

Visual Resources Figure 14 represents the existing view toward the project site from the highway apron of the closest residence west of the project site on SR-14, approximately 0.4-mile from the project site.

Visual Sensitivity

The observable KOP 3 physical landscape consists of the north and southbound lanes of SR-14, ruderal vegetation and creosote bush scrub, the Rand Mountains and a view of open sky. The view offers some variety or contrast in vegetation. The estimated public appeal of the visual quality at KOP 3 is considered to be moderate.

Viewer concern is considered moderately low. Viewers at this KOP location would mainly consist of motorists on SR-14. The type of motorist would be defined as freeway travelers. Along this segment of SR-14, these users of the freeway system would generally be engaged in long distance travel, and travel at normal freeway speeds whose focus of attention is on long range non-peripheral views.

From this KOP, the viewer would be accustomed to a view of the open space of Fremont Valley, sky and the mountains. The mountains do not have a focal point that draws the viewer’s eye to a feature.

Caltrans 2007 traffic count information shows the annual average daily trips (AADT) along SR-14 at Redrock Randsburg Road at SR-14, approximately four miles north of the project site, were 6,700 north bound trips and 6,600 south bound trips. This number of potential exposures of the project site is considered moderate to high.

Viewers at KOP 3 would have an unobstructed, high visibility, high duration view of the proposed project site. Overall viewer exposure is considered moderately high.

The visual sensitivity at KOP 3 is considered to be moderate.

Visual Change

Visual Resources Figure 15 is a simulation of the proposed project’s publicly visible structures after the completion of construction showing both transmission line options.

Visible project features would include an east view of the north-south configuration of the parabolic troughs, transmission pole lines, the administration building and warehouse. The degree of contrast introduced by the structures is considered moderately low; the contrast can be seen but does not attract attention at the KOP.

The simulation shows that the proportionate size relationship of the publicly visible project structures to other existing human-made and natural components would be moderately low in the total field-of-view. Project structures would not block the view of Rand Mountains or sky from KOP 3.

Structural contrast introduced by the parabolic troughs and structures could vary greatly depending upon surface treatment. Staff has recommended Condition of Certification **VIS-1** to provide for the project surface structures use neutral colors and non-reflective surface treatments.

The overall visual change caused by the introduction of the proposed project’s structures into the view is considered to be moderately low as a result of a moderately low visual contrast, moderately low visual scale, and low view blockage.

When considering the moderate overall visual sensitivity and the moderately low overall visual change, the introduction of the proposed project’s publicly visible structures would introduce a less than significant visual impact at this KOP.

KOP 4 - Northbound State Route 14, Approximately Two Miles South of Project Site Looking Northeast

Visual Resources Figure 16 represents the existing view from northbound SR-14, approximately two miles south and 0.4-mile west of the project site.

Visual Sensitivity

The observable KOP 4 physical landscape consists of the gentle sloping expanse of northern Fremont Valley with ruderal vegetation, Mohave Creosote Bush Scrub, a faint view of Rancho Seco and the El Paso Mountains. The view offers variety and contrast in vegetation. The mountains do not have a focal point that draws the viewer's eye to a feature. The ridgeline is not distinct in form. SR-14 is not identified as a State Scenic Highway or as a county scenic highway. The estimated public appeal of the visual quality at KOP 4 is considered to be moderate.

Viewer concern is considered moderate. Viewers at this KOP location would mainly consist of motorists on SR-14. The type of motorist would be defined as freeway travelers. They have a low to moderate sensitivity to the visual environment.

From this KOP, the viewer would be accustomed to a view of the open space of Fremont Valley, sky and the mountains.

Caltrans 2007 traffic count information shows the AADT of 6,700 north bound trips and 6,600 south bound trips on SR-14. This number of potential exposures of the project site is considered moderate to high.

Viewers at KOP 4 would have an unobstructed, high visibility, high duration view of the proposed project site. Overall viewer exposure is considered moderately high.

The visual sensitivity at KOP 4 is considered to be moderate.

Visual Change

Visual Resources Figure 17 represents a simulation of the proposed project's publicly visible structures after the completion of construction showing both transmission line options.

Publicly visible project structures would include the parabolic troughs, power block structures, the administration building and warehouse, and transmission lines poles. The approximate 1,250 acres of parabolic troughs would alter the texture of the existing desert floor. The degree of contrast introduced by the structures is considered moderately low; the contrast can be seen but does not attract attention at the KOP.

Surface structure color contrast could be strong if a neutral paint color is not used. Staff has recommended Condition of Certification **VIS-1** to provide for the project surface structure's use of neutral colors and non-reflective surface treatments.

The simulation shows that the proportionate size relationship of the publicly visible project structures to other existing human-made and natural components would be moderate in the total field-of-view. Project structures would not block the view of mountains, or sky from KOP 4.

The overall visual change caused by the introduction of the proposed project's structures into the view is considered to be moderately low as a result of a moderately low visual contrast, moderate visual scale, and low view blockage.

When considering the moderate overall visual sensitivity and the moderately low overall visual change, the introduction of the proposed project's publicly visible structures would introduce a less than significant visual impact at this KOP.

KOP 5 – Southbound State Route 14, East of the Project Site, Looking South

Visual Resources Figure 18 represents the existing view of southbound SR-14 looking towards the location of the project's proposed overhead transmission line crossing of the highway. The project owner has proposed two overhead transmission line crossing options.

Visual Sensitivity

The observable KOP 5 physical landscape consists of the southbound lanes of SR-14 and ruderal vegetation. The view offers variety and contrast in vegetation. SR-14 is not identified as a State Scenic Highway or as a county scenic highway. The estimated public appeal of the visual quality at KOP 4 is considered to be moderately low.

Viewer concern is considered low. Viewers at this KOP location would consist of motorists on SR-14. The type of motorist would be defined as freeway travelers. They have a low to moderate sensitivity to the visual environment.

The number of potential motorist exposures according to Caltrans 2007 traffic count information shows 6,800 north bound trips and 9,800 south bound AADT based on counts on SR-14 at Randsburg Cutoff/California City Boulevard. This number of potential exposures is considered moderate to high.

Viewers on SR-14 would have an unobstructed, highly visible, high duration view of an overhead transmission line at the KOP. Overall viewer exposure is considered moderately high.

The visual sensitivity at KOP 4 is considered to be moderate.

Visual Change

Visual Resources Figure 19a shows a simulation of the proposed project's publicly visible structures after the completion of construction with overhead transmission option one. **Visual Resources Figure 19b** represents the project's publicly visible structures with overhead transmission option two.

The publicly visible project structures would include the 110-foot tall steel monopoles. The contrast by the structures would be low. Staff has previously recommended

Condition of Certification **VIS-1** to provide for the project surface structure's use of neutral colors and non-reflective surface treatments minimize structure contrast. The simulation shows that the proportionate size relationship of project structures to other existing human-made and natural components would occupy a low portion of the total field-of-view in KOP 5. The structures would block a small view of sky in the KOP 5 view.

The overall visual change caused by the introduction of the proposed project's structures into the view is considered to be low as a result of a low contrast, low visual scale, and low view blockage.

When considering the moderate overall visual sensitivity and the moderately low overall visual change, the introduction of the proposed project's publicly visible structures would introduce a less than significant visual impact at this KOP.

KOP 6 – Chuckwalla Mountain Hiking Trail Looking East

Visual Resources Figure 20 represents existing view from the public hiking trail to Chuckwalla Mountain (5,036 foot elevation) in the Piute Mountain Range, approximately two miles west of the project site. The hiking trail is approximately six miles south of Jawbone Canyon Road.

Visual Sensitivity

The observable physical landscape from KOP 6 includes an elevated open space panoramic view of the Fremont Valley. The view offers variety and texture contrast in vegetation and soil (sand, ruderal vegetation, and creosote bush scrub). Human-made modifications in the view include the Fremont Valley Ranch farm buildings, and the Honda Proving Center's five-mile asphalt road track. The Rand Mountains spanning from the northeast to the southwest and horizon are in the distant view. No county, state, or federal designated scenic vistas are identified in the study area. The estimated public appeal of the visual quality of the KOP 6 view is considered to be moderately high.

Viewer concern is considered high. The primary viewers at this KOP are hikers. Hikers are considered to have a high sensitivity to the visual environment. From this KOP, the viewer would be accustomed to a view of valley floor and surrounding mountains.

Hikers would have an unobstructed high visibility view of the project site at the KOP location. The view exposure would be of long (high) duration from this KOP. The number of hikers (viewers) that use the trail is unknown to staff at this time. Staff used a conservative estimate of 25 hikers per day for the purposes of this analysis. This number of hikers that may potentially be visually exposed to the project site is considered low. Overall viewer exposure at KOP 6 is considered moderate.

The visual sensitivity at KOP 6 is considered to be moderately high.

Visual Change

Visual Resources Figure 21a shows a simulation of the proposed project's publicly visible structures after the completion of construction with overhead transmission option one. **Visual Resources Figure 21b** represents the project's publicly visible structures with overhead transmission option two.

Publicly visible project structures would include the transmission lines poles and parabolic troughs. Power block structures and the administration building and warehouse are not visually discernable in the simulation. The transmission line monopoles would introduce a vertical line, and light colored appearance to the setting. The approximate 1,250 acres of parabolic troughs would alter the texture of the valley floor. The parabolic troughs would have a legible form with high unity, and to some observers could be perceived as an interesting and vivid, albeit a human-made sight. The degree of contrast introduced by the structures is high at the KOP. The contrast demands attention, would not be overlooked and would be dominant in the landscape from this KOP.

The simulation shows that the proportionate size relationship of the publicly visible project structures to other existing human-made and natural components would be codominant (moderate) in the total field-of-view. Project structures would not block the view of mountains, sky, or valley floor from KOP 6.

The overall visual change caused by the introduction of the proposed project's structures into the KOP 6 view is considered to be moderate as a result of high contrast, moderate visual scale, and low view blockage.

When considering the moderately high overall visual sensitivity and the moderate overall visual change, the introduction of the publicly visible structures would introduce a significant visual impact at this KOP. No mitigation measures have been identified by staff to reduce the impact to a less than significant at this KOP.

PROJECT LINEARS

The BSEP proposes to connect to the Los Angeles Department of Water and Power (LADWP) transmission system approximately 1.5 miles west-southwest of the project site. Two existing LADWP transmission lines, the Celilo-Sylmar 500 kV DC intertie line, and the Inyo-Barren Ridge 230 kV line are at this location. Both lines run within an approximate 250-foot wide, north-south LADWP right of way (ROW). The applicant is seeking approval of two transmission line options for interconnecting the project. Only one option is to be selected. A final transmission line route is to be selected upon completion of the System Impact Study and Facilities Study by LADWP.

The proposed transmission line involves the installation of 36 steel/concrete monopoles, 79 feet and 110 feet in height and a span length expected to average approximately 500 feet. New transmission poles are to be of a neutral color and non-reflective surface (BS 2008a, pg. 5.15-12). The degree of contrast introduced by the transmission poles as simulated in **Visual Resources Figure 19a** and **19b** appears low in the setting.

Water for the project's domestic and process use is to be supplied from onsite groundwater wells. Water pipelines are to be installed underground. With the burying of the project's pipelines and restoration of surface areas, the long-term visual impact would be minimized.

Natural gas would be supplied by a 17.6-mile natural gas pipeline that interconnects with an existing Southern California Gas (SCG) Company line west of California City. Most major segments of pipeline construction equipment will remain along the pipeline ROW during construction. Excavated earth material would be stored within the construction ROW. During nonworking hours, any open trench would be covered with wood or other material of sufficient strength to support wildlife (BS 2008a, pg. 2-28).

The project owner proposes to bury project-related linear pipelines. With the burying of pipelines and the restoration of the ground surfaces, the linear routes would not create a change to the existing visual condition. Staff has recommended Condition of Certification **VIS-2** to ensure the restoration of ground surfaces affected by temporary construction activities so that these disturbed areas do not become sources of long-term visual impacts.

PUBLICLY VISIBLE WATER VAPOR PLUMES

The project proposes use of an evaporative cooling tower. When the evaporative cooling tower is operated at times of low temperature and high humidity, the potential exists for visible water vapor plumes. A formed plume potentially could substantially degrade the existing visual character or quality of the project site and its vicinity.

Staff estimated the proposed project's cooling tower plume frequencies and dimensions using the Combustion Stack Visible Plume (CSVP) model and three-years (2002-2004) of meteorological data from the Mojave Airport obtained by the applicant from the U.S. EPA Air Quality System Meteorological Data System, and relative humidity data from Fox Field in Lancaster, California. Please refer to **APPENDIX VR-2** at the end of this visual resources section for a more complete description of staff's visible plume modeling analysis.

The cooling tower operation for this project is significantly different than the dozens of cooling towers evaluated for siting cases from 2001 to present. Specifically, the heat rejection load to the cooling tower is specifically related to the sun angle (time of day and year) that impacts the total power production capacity of the facility. Therefore, the cooling tower operation starts at low heat rejection loads each morning and builds until the afternoon when the heat rejection load drops as the sun sets. Staff has attempted to mimic, in a simple way, the complex operating profile of the cooling tower exhaust modeling inputs. Additionally, the hourly cooling tower exhaust conditions are interpolated for the hourly ambient conditions (temperature and relative humidity) based on the assumed heat rejection for each operating cooling tower cell.

The applicant provided estimated average heat rejection data for each hour of each month (BS 2009). The applicant also noted that at a minimum one half of the cells (assumed by staff to be 5 of 11) would have fans operating. However, the heat rejection turndown is a much greater value than one-half, which during very cold periods would likely cause freezing problems in the cooling tower if more cell fans are not turned off. Therefore, to be conservative, staff has assigned an average heat rejection of 39 MW of heat rejection to determine the number of cells operating on average for each hour of each month. The applicant's heat rejection basis and staff's cooling tower cell operating assumptions are provided in **APPENDIX VR-2**, **Visible Plume Tables 2** and **3**, respectively.

For the worst-case operating profile, visible water vapor plumes from the project's cooling towers are predicted to have a plume frequency of 33.5 percent of the seasonal (November through April) daylight clear hours. A plume frequency threshold of 20 percent of seasonal (typically from November through April) daylight no rain/fog high visual contrast (i.e. "clear") hours is used to assess a potential plume appearance impact significance. If it is determined that the seasonal daylight clear hour plume frequency is greater than 20 percent, then plume dimensions are determined and a significance analysis is included in the Visual Resources section of the Staff Assessment for the proposed project (see **APPENDIX VR-2**).

Staff considers the 20th percentile plume to be the reasonable worst case plume dimensions on which to base its visual impact analysis. Staff assesses the visual change in terms of contrast, dominance and view blockage that would be caused by the 20th percentile plume dimensions. The 20th percentile plume is the smallest of the plumes that are predicted to occur zero to 20 percent of the time. Eighty (80) percent of the time the dimensions of the clear hour plumes would be smaller than the 20th percentile plume dimensions. A one percentile clear hour plume would be extremely large (physical size) and very noticeable to a wide area. It occurs very infrequently.

The 20th percentile plume dimensions from the proposed project's eleven-cell cooling tower are predicted to be 111 feet high, 77 feet wide, and 86 feet long. Since the proposed cooling towers are 44.3 feet tall, the effective plume height over the top of the cooling tower would be 66.7 feet. Staff did not prepare a photo simulation of the water vapor plumes for the project.

The 20th percentile plume size is not dissimilar in magnitude to those predicted by the applicant in the AFC using the SACTI model (BS 2008b), considering the differences in approach, with the exception that the SACTI model groups the met data and does not model calm hours which will cause some underestimation of maximum plume height during worst case hourly conditions.

The 20th percentile plume dimensions for the project's cooling tower plumes are predicted to visually appear subordinate when compared to other manmade and natural elements in the KOP viewsheds. Considering the visual sensitivity of the existing landscape and viewing characteristics, the small size of the two BSEP boilers and their limited operation, the degree of visual change potentially introduced by plumes is considered to be less than significant.

CONSTRUCTION IMPACTS

Construction Laydown Area

A construction laydown and construction parking area is to be provided on the 2,012 acre project site. The initial laydown area involves 22 acres west of the proposed power block location (see **Visual Resources Figure 3**) and a construction parking area on 2.5 acres to the south of it. The laydown area is to be relocated periodically as the solar collector field is built out.

Construction Activities

Construction activities for the project would occur over an approximate 25-month period; Monday through Friday between the hours of 7:00 am and 7:00 pm. The construction sequence for project construction includes the following:

- *Site Preparation:* this includes detailed construction surveys, mobilization of construction staff, grading, and preparation of drainage features. Grading for the solar field, power block, and rerouted wash will be completed during the first nine months of the construction schedule.
- *Foundations:* this includes excavations for large equipment (steam turbine generator, solar steam generator, generator step-up transformer), cooling tower, etc.), footings for the solar field, and ancillary foundations in the power block.
- *Major Equipment Installation:* once the foundations are complete the larger equipment will be installed. The solar field components will be assembled in an onsite erection facility and installed on their foundations.
- *Balance of Project:* with the major equipment in place, the remaining field work will be piping, electrical, and smaller component installations (BS 2008a, pg. 2-27).

Construction activities on the BSEP site and use of the laydown area would be highly visible to the surrounding area due to the flat, open viewing conditions and would visually contrast significantly with the existing character of the area.

Typically screening of construction site activities, and the laydown and construction parking areas is accomplished by attaching fabric or adding wooden slats to a perimeter fence. This screening is effective in limiting ground level exposure of a project close to the viewer. Staff believes that the use of fabric or wooden slat screening would provide limited surface level visual screening of the construction site from SR- 14 viewers due to the project site’s size and distance from SR-14, particularly the laydown area and the power block.

Lighting required to facilitate nighttime construction activities, to the extent feasible must be consistent with worker safety codes, directed toward the center of the construction site, shielded to prevent light from straying offsite, and task-specific. Staff has proposed Condition of Certification **VIS-3** to formalize temporary lighting measures during construction activity and on the laydown area.

The project owner proposes restoration of ground surfaces affected by temporary construction activities. With the effective implementation of surface restoration, project construction activities would not result in a long-term visual degradation to the existing visual condition. Staff has recommended Condition of Certification **VIS-2** to formalize restoration of ground surfaces measures proposed by the project owner.

Staff concludes the project's temporary construction activities would create a substantial visual impact that would be mitigated to a less than significant impact with the effective implementation of Conditions of Certification **VIS-2** and **VIS-3**.

D. LIGHT OR GLARE

> "Would the project create a new source of substantial light or glare that would adversely affect day or nighttime views in the area?"

The BSEP during operation has the potential to introduce offsite light and glare to surrounding properties, and up-lighting to the nighttime sky if typically bright exterior lights were not hooded and lights were not directed onsite.

Light trespass and glare[2] are quite subjective, they are difficult to eliminate, but they can be minimized through good design practices. In many cases, all that is required is the proper placement of poles, selection of lights, and shielding accessories.

The applicant states in the AFC that project light fixtures will be restricted to areas required for safety, security, and operations. Lighting will be directed onsite; it would be shielded from public view, and non-glare fixtures and use of switches, sensors, and timers to minimize the time that lights not needed for safety and security are on would be specified. To the extent feasible and consistent with worker safety codes, lighting that might be installed to facilitate possible nighttime construction activities will be directed toward the center of the construction site and shielded to prevent light from straying offsite. Task-specific construction lighting will be used to the extent practical while complying with worker safety regulations (BS 2008a, pg. 5.15-15). Staff believes that the project owner's description of their proposed light mitigation would reduce offsite light impacts to the area; however, the description does not specifically describe what the measures may consist of during the project's operation. Staff has recommended Condition of Certification **VIS-4** to formalize the applicant's proposed lighting measures in a light management plan. Staff concludes the introduction of project lighting during operation to the area would create a substantial visual impact that would be mitigated to a less than significant impact with the effective implementation of Condition of Certification **VIS-4**.

More than half of the 2,012-acre project site will be taken up by parabolic trough solar collector arrays. The parabolic troughs track the sun's movement across the sky. Troughs are stowed facing the ground so no glare occurs. When a parabolic trough rotates from stow into the tracking position, a horizontal glare may occur for a short period of time at the beginning and end of daily operations. A parabolic trough's tracking system during normal operation is designed to minimize horizontal glare. When glare does occur it is typically addressed by correctly aligning the unit.

[2] For the purposes of this analysis "direct glare" is used and is defined as the visual discomfort resulting from insufficiently shielded light sources in the field of view.

The project owner, in the AFC states that project equipment other than the solar arrays will have non-reflective surfaces and neutral colors to minimize their visual impacts (BS 2008a, pg. 5.15-9). Construction of the project's 230-kV transmission line involves installation of concrete or steel power poles. The insulators are to be made of a non-reflective and non-refractive material, and the conductors are to be non-specular (i.e., their surfaces will have a dulled finish so that they do not reflect sunlight) (BS 2008a, pg. 5-15-10). With effective implementation of the proposed surface treatment, project structures would not be a source of substantial glare that could adversely affect daytime views. Staff has proposed Condition of Certification **VIS-1** to formalize surface treatment measures.

CUMULATIVE IMPACTS AND MITIGATION

As defined in Section 15355 of the CEQA Guidelines (California Code of Regulations, Title 14), a cumulative impact is created as a result of the combination of the project under consideration together with other existing or reasonably foreseeable projects causing related impacts. Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time. In other words, while any one project may not create a significant impact to visual resources, the combination of the new project with all existing or planned projects in an area may create significant impacts. A significant cumulative impact would depend on the degree to which (1) the viewshed is altered; (2) view of a scenic resource is impaired; or (3) visual quality is diminished.

Honda Proving Center of California is a test track used primarily for testing Honda and Acura automobiles. Motorcycles are also tested there. The Center offers a variety of environments for vehicle evaluation including on-site paved test courses modeled after common North American public roads. Other on-site courses include dirt roads, gravel roads, Motocross tracks and desert test courses.The Proving Center has a 7.5 mile oval track, as well as a five-mile winding road course. The Center is located approximately ½ mile east of the BSEP site. The facility is not open to the public. Despite its large size, the complex is hard to see from public roads.

Two projects have been identified in the AFC for the cumulative impacts analysis: the Pine Tree Wind Development Project and Los Angeles Department of Water and Power's (LADWP) Barren Ridge-Castaic Transmission Project. The Pine Tree Wind Development Project is currently under construction and consists of 80, 1.5 megawatt (MW) wind turbine generators located on approximately 8,000 acres about six miles west of the BSEP site. It is expected to be completed in 2009.

The LADWP Barren Ridge-Castaic Transmission Project is in the environmental review process that started in early 2008. The project upgrades and builds new transmission capacity from the Barren Ridge Switching Station to the Castaic Power Plant in Los Angeles County. The Barren Ridge-Castaic Transmission Project would involve the installation of new and/or additional utility poles. The project would be located approximately two miles southwest of the BSEP.

The existing Honda Proving Center and the proposed BSEP, Pine Tree Wind Development Project, and LADWP project introduce publicly visible structures to a desert area. Though noticeable they would not be so great as to constitute a substantial degradation of the existing visual setting of the northern Fremont Valley. The projects would not impair the view of an identified federal, state, or local scenic resource.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

Staff considers federal, state, and local LORS relevant to aesthetics, or protection and preservation of sensitive visual resources. Staff examines land use planning documents such as a Corridor Management Plan, Local Coastal Plan, General Plan, zoning ordinances, and other government or municipal code sections applicable to the project site and surrounding area pertaining to aesthetics, or protection and preservation of sensitive visual resources.

Visual Resources Table 3 provides an analysis of the applicable LORS pertaining to aesthetics, or preservation and protection of sensitive visual resources relevant to the proposed project. Conditions of Certification are proposed to make the project conform to a LORS where appropriate.

VISUAL RESOURCES Table 3
Proposed Project's Consistency with
LORS Applicable to Visual Resources

LORS		Consistency Determination	Basis for Consistency
Source	**Policy and Strategy Descriptions**		
Local			
Kern County General Plan **Land Use, Open Space and Conservation Element**			
Chapter 1 – General Provisions Section 1.10.7 Lighting and Glare	Light and glare from discretionary new development projects are to be minimized in rural as well as urban areas. Encourages the use of low-glare lighting to minimize nighttime glare effects on neighboring properties.	YES AS CONDITIONED	The project owner plans to reduce offsite lighting impacts; lighting at the BSEP is to be restricted to areas required for safety, security, and operation. Exterior lights are to be hooded, and lights directed onsite so that light or glare will be minimized. Low-pressure sodium lamps and fixtures of a non-glare type are to be used. Switched lighting is to be provided for areas where continuous lighting is not required for normal operation, safety, or security; this will allow these areas to remain dark most of the time (BS 2008a, pg. 5.15-9). Project construction activities typically will occur during normal Monday through Friday working hours, although nighttime activities may occur at certain times during the construction period depending on the project schedule. When and if nighttime construction activities take place, illumination will be provided that meets State and Federal worker safety regulations. To the extent possible, the nighttime construction lighting will point toward the center of the site where activities are occurring, and will be shielded. Task specific lighting will be used to the extent practical. Correspondence received from the Kern County Planning Department regarding the BSEP dated September 16, 2008 has recommended a condition of approval pertaining to lighting. The recommendation is that all exterior lighting shall be directed away from adjacent properties and road. The lighting standards shall be

			equipped with glare shields or baffles and shall not exceed 40 feet in height above grade (KC 2008f). Staff has proposed Condition of Certification **VIS-3** and **VIS-4** to minimize light trespass from the site.
Chapter 2 – Circulation Element Section 2.3.9 Scenic Route Corridors	A scenic route must be officially set as a Scenic Route by the Kern County Board of Supervisors, or the State of California.	YES AS PROPOSED	SR-14 is not listed as a state scenic highway. The County of Kern has not designated SR-14 as a county scenic highway (Caltrans2007a).
Chapter 5 – Energy Element Section 5.4.7 Transmission Lines	Discourages the siting of above-ground transmission lines in visually sensitive areas.	YES AS PROPOSED	The greatest number of public exposures to the BSEP is from SR-14. Also, the project's transmission lines would cross over SR-14 connecting to the Barren Ridge Switching Station. SR-14 is not listed by the state or the county of Kern as a scenic highway. In addition, the transmission route does not cross a unique water feature; a unique physical geological terrain feature; a tree having a unique visual/historical importance to a community; historic building; or a designated federal scenic byway.
Kern County Code Title 19 Zoning			
Section 19.12.070 Yard and Setbacks	A. **Front Yard**. Front-yard minimum setback for all buildings: 1. Fifty-five (55) feet from the legal centerline of any existing or proposed public or private local street or access easements. 2. Seventy (70) feet from the legal centerline of any existing or proposed secondary highway. 3. Eighty (80) feet from the legal centerline of any existing or proposed major highway. In no case shall the front-yard minimum setback be less than twenty five (25) feet from the right-of-way established by any Official or Specific Plan Line, street, or access easement. B. **Side Yard**. There shall be a side yard on each side of a building of not less than five (5) feet, except that on the street side of corner lots, buildings shall be set back a minimum of ten (10) feet from the right-of-way of any local street, existing or proposed secondary or major	YES AS PROPOSED	As shown on Figure1-2 in the AFC the project would comply with the county's yard and setbacks.

	highway, or the right-of-way established by any Official or Specific Plan Line. C. **Rear Yard**. There shall be a rear yard of not less than five (5) feet except that in the case of through lots, the designated rear yard shall be in accordance with the front-yard setback requirements.		
Section 19.12.080 Height Limits	B. There is no height limit on nonresidential structures, except in areas of protected military airspace as specified in Section 19.08.160.B.	YES AS PROPOSED	The county's Exclusive Agriculture (A) District has no height limit on nonresidential structures. There are no residential structures proposed on the BSEP site.
Section 19.12.110 Signs	The following types of signs are permitted in the A District in accordance with the requirements of Chapter 19.84 of this title: A. Temporary real estate signs advertising the property for sale or for rent, not to exceed sixteen (16) square feet each, excluding the area of any vertical and/or horizontal support members. B. Temporary construction signs. C. Temporary political, religious, or civic campaign signs. D. Agricultural signs. E. Agricultural industry signs, when approved in conjunction with a conditional use permit. F. Institutional identification signs, when approved in conjunction with a conditional use permit. G. Off-site directional signs for agricultural product direct marketing facilities pursuant to Subsection C of Section 19.12.130 of this chapter. H. Oilfield identification signs.	YES AS CONDITIONED	The project's AFC and supplements do not discuss the installation of onsite or offsite signs. Correspondence received from the Kern County Planning Department regarding the BSEP dated September 16, 2008 has recommended a condition of approval pertaining to signs. The recommendation is that all signs shall comply with the signage regulations of the applicable base zone district and with Chapter 19.84 of the Zoning Ordinance and be approved by the Director of the Kern County Planning Department prior to installation (KC 2008f). Staff has provided Condition of Certification **VIS-5** in case a sign(s) is provided to serve the project.
Section 19.12.120 Landscaping	No landscaping is required in the A District, except where the proposed use is subject to a plot plan review pursuant to Chapter 19.80. Section 19.86.070 where landscaping is required pursuant to this chapter, the plot plan submitted in conjunction with any building permit application shall show the areas to be landscaped, the type of	YES AS CONDITIONED	The project's AFC and supplements to it do not discuss the planting of landscaping on the project site. Correspondence received from the Kern County Planning Department regarding the BSEP dated September 16, 2008 has recommended a condition of approval pertaining to landscaping. The recommendation is that a comprehensive landscaping and

	landscaping proposed and amount, and shall state the proposed method of irrigation. Where no building permits are required to establish a new use on any parcel for which landscaping is required, a plot plan showing this information shall be submitted to the Planning Director prior to commencement of said use.		irrigation plan be approved by the Director of the Kern County Planning Department in accordance with the requirements of Chapter 19.86 of the Zoning Ordinance. A minimum of 5% of the developed area shall be landscaped with xeriscape or drought tolerant plantings and continuously maintained in good condition. Landscaping shall be installed or bounded for prior to occupancy of the building or site. Given the remote nature of the project site, as an alternative requirement the project may contribute the equivalent cost of the landscaping to the Kern County Parks and Recreation district, school or other non-profit organization in Kern County (KC 2008f). Staff has provided Condition of Certification **VIS-6** to address the County's code.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

As of this PSA, no agency or public comments have been received on the visual resources section.

CONCLUSIONS

The visual analysis focused on two main issues. (1) Would construction and operation of the project introduce an aesthetic impact in accordance to CEQA? (2) Would the project comply with applicable LORS pertaining to aesthetics, or preservation and protection of sensitive visual resources?

1. There is no national, state or county designated scenic vista in the project vicinity.

2. There are no identified scenic resources in the selected KOP 1 through KOP 6 views.

3. The proposed project would be seen from elevated locations around the northern Fremont Valley. The KOP 2 and KOP 6 views create an unmitigable significant adverse change to the visual character and quality to the existing physical setting. The project would change the existing character of the desert floor of the Fremont Valley from a moderately disturbed desert floor landscape to a highly human-altered landscape, and the introduction of the radiance from the parabolic trough arrays during operation would be prominent.

4. The project's two small size boilers and limited operation are expected to create a less than significant publicly visible water vapor plume impact to the physical setting.

5. The project would generate a less than significant new source of light or glare to nighttime or daytime views with the effective implementation of the conditions of certification.

6. The existing Honda Proving Center, and the proposed BSEP, Pine Tree Wind Development Project and the LADWP projects, though noticeable, would not be so significant as to constitute a substantial cumulative visual impact to the setting of the northern Fremont Valley.

7. The project would comply with all applicable laws, ordinances, regulations, and standards pertaining to aesthetics, or preservation and protection of sensitive visual resources discussed in Visual Resources Table 3.

PROPOSED CONDITIONS OF CERTIFICATION

Surface Treatment of Project Structures and Buildings

VIS-1 The project owner shall color and finish the surfaces of all project structures and buildings visible to the public to ensure that they: (1) minimize visual intrusion and contrast by blending with the landscape; (2) minimize glare; and (3) comply with local design policies and ordinances. The transmission line conductors shall be non-specular and non-reflective, and the insulators shall be non-reflective and non-refractive.

The project owner shall submit a surface treatment plan to the CPM for review and approval. The surface treatment plan shall include:

a. A description of the overall rationale for the proposed surface treatment, including the selection of the proposed color(s) and finishes;

b. A list of each major project structure and building (e.g., building, tank, and pipe; transmission line towers and/or poles; and fencing), specifying the color(s) and finish proposed for each. Colors must be identified by vendor, name, and number; or according to a universal designation system;

c. One set of color brochures or color chips showing each proposed color and finish;

d. A specific schedule for completing the treatment; and

e. A procedure to ensure proper treatment maintenance for the life of the project.

The project owner shall not request vendor surface treatment of any buildings or structures during their manufacture, or perform final field treatment on any buildings or structures, until the project owner has received treatment plan approval by the CPM.

The project owner shall notify the CPM that surface treatment of all listed structures and buildings has been completed and is ready for inspection; and shall submit one set of electronic color photographs from KOPs 1, 3, 4, and 5 showing the “as built” surface treated structures and buildings.

Verification: At least 45 days prior to applying vendor color(s) and finish(es) for structures or buildings to be surface treated during manufacture, the project owner shall submit the proposed treatment plan to the CPM.

If the CPM determines that the plan requires revision, the project owner shall provide to the CPM a plan with the specified revision(s) for review and approval by the CPM before any treatment is applied. Any modifications to the treatment plan must be submitted to the CPM for review and approval.

Within ninety (90) days after the start of commercial operation, the project owner shall notify the CPM that surface treatment of all listed structures and buildings has been completed and is ready for inspection; and shall submit one set of electronic color photographs from KOPs 1, 3, 4, and 5 showing the “as built” surface treated structures and buildings.

The project owner shall provide a status report regarding surface treatment maintenance in the Annual Compliance Report. The report shall specify a): the condition of the surfaces of all structures and buildings at the end of the reporting year; b) major maintenance activities that occurred during the reporting year; and c) the schedule of major maintenance activities for the next year.

Surface Restoration

VIS-2 The project owner shall remove all evidence of temporary construction activities, and shall restore the ground surface to the original condition or better condition, including the replacement of any vegetation during construction where project development does not preclude it. The project owner shall submit to the CPM for approval a surface restoration plan, the proper implementation of which will satisfy these requirements. The project owner shall complete surface restoration within 60 days after the start of commercial operation.

Verification: At least 60 days prior to the start of commercial operation, the project owner shall submit the surface restoration plan to the CPM for review and approval.

If the CPM notifies the project owner that any revisions of the surface restoration plan are needed, within 30 days of receiving that notification the project owner shall submit to the CPM a plan with the specified revisions.

The project owner shall complete surface restoration within 60 days after the start of commercial operation. The project owner shall notify the CPM within seven days after completion of surface restoration that the restoration is ready for inspection.

Construction Lighting

VIS-3 The project owner shall ensure that lighting on the construction site and the construction laydown area that minimizes potential night lighting impacts, and that at a minimum includes the following:

a. All lighting shall be of minimum necessary brightness consistent with worker safety and security;

b. All fixed position lighting shall be shielded/hooded to direct light downward, and toward the area to be illuminated preventing direct illumination of the night sky and direct light trespass (direct light extending outside the boundaries of the solar farm site, the construction laydown area, or the site of construction of ancillary facilities, including any security related boundaries);

c. Wherever feasible and safe and not needed for security, lighting shall be kept off; and

d. If the project owner receives a complaint about construction lighting, the project owner shall notify the Compliance Project Manager (CPM) and shall use the complaint resolution form included in the General Conditions section of the Compliance Plan to record each lighting complaint and to document the resolution of that complaint. The project owner shall provide a copy of each complaint form to the CPM.

Verification: Within seven days after the first use of construction lighting, the project owner shall notify the CPM that the lighting is ready for inspection.

If the CPM notifies the project owner that modifications to the lighting are needed to minimize impacts, within 15 days of receiving that notification the project owner shall implement the necessary modifications and notify the CPM that the modifications have been completed.

Within 48 hours of receiving a lighting complaint, the project owner shall provide to the CPM; a) a report of the complaint, b) a proposal to resolve the complaint, and c) a schedule for implementation of the proposal. The project owner shall notify the CPM within 48 hours after completing implementation of the proposal. The project owner shall provide a copy of the completed complaint resolution form to the CPM in the next Monthly Compliance Report.

Permanent Exterior Lighting

VIS-4 To the extent feasible, consistent with safety and security considerations and commercial availability, the project owner shall design and install all permanent exterior lighting such that a) light fixtures do not cause obtrusive spill light beyond the project site; b) lighting does not cause excessive reflected glare; c) direct lighting does not illuminate the nighttime sky; d) illumination of the project and its immediate vicinity is minimized, and e) lighting complies with local policies and ordinances. The project owner shall submit to the CPM for approval a lighting management plan that includes at a minimum the following:

a. A process for addressing and mitigating lighting related complaints;

b. Lighting shall incorporate commercially available fixture hoods/shielding, with light directed downward or toward the area to be illuminated;

c. All lighting shall be of minimum necessary brightness consistent with operational safety and security; and

d. Lights in high illumination areas not occupied on a continuous basis (such as maintenance platforms) shall have (in addition to hoods) switches, timer switches, or motion detectors so that the lights operate only when the area is occupied.

Verification: At least 14 days prior to ordering any permanent exterior lighting, the project owner shall contact the CPM to determine the required documentation for the lighting management plan.

At least 60 days prior to ordering any permanent exterior lighting, the project owner shall submit to the CPM for approval a lighting management plan. If the CPM determines that the lighting management plan requires revision, the project owner shall provide to the CPM a plan with the specified revision(s) for approval. The project owner shall not order any exterior lighting until receiving CPM approval of the lighting management plan.

Prior to commercial operation, the project owner shall notify the CPM that the lighting has been installed and is ready for inspection. If after inspection the CPM notifies the project owner that modifications to the lighting are needed, within 30 days of receiving notification the project owner shall implement the modifications and notify the CPM that the modifications have been completed and are ready for inspection.

Within 10 days of receiving a lighting complaint, the project owner shall provide the CPM with a complaint resolution form report as specified in the Compliance General Conditions including a proposal to resolve the complaint, and a schedule for implementation. The project owner shall notify the CPM within 10 days after completing implementation of the proposal. A copy of the complaint resolution form report shall be submitted to the CPM within 30 days of complaint resolution.

Signage

VIS-5 The project owner shall install minimal signage visible to the public, which shall a) have unobtrusive colors and finishes that prevent excessive glare; and b) be consistent with the applicable design and development standards found in Chapter 19.84 Signs of the Kern County Code. The design of any signs required by safety regulations shall conform to the criteria established by those regulations.

The project owner shall submit any publicly visible signs for the project to the Director of the Kern County Planning Department for comment and to the CPM for approval. The project owner shall not implement the plan until the project owner receives approval of the submittal from the CPM.

Verification: Prior to the start of commercial operation and at least 30 days prior to installing signs, the project owner shall submit a sign plan for the project to the Director of the Kern County Department of Planning for comment and to the CPM for approval. The project owner shall provide a copy of the Director of the Kern County Planning Department comments to the CPM.

If the CPM determines that the sign plan requires revision, the project owner shall provide to the CPM a plan with the specified revision(s) for approval by the CPM before any signage visible to the public is installed.

The project owner shall inform that CPM that signs have been installed and provide the CPM with electronic files of the color photographs of the signage.

Landscaping

VIS-6 The project owner shall provide a comprehensive landscaping and irrigation plan for the project site in accordance with the requirements of Chapter 19.86 of the Kern County Zoning Ordinance. A minimum of five (5) percent of the developed area shall be landscaped with xeriscape or drought tolerant plantings that are to be continuously maintained in good condition. Landscaping shall be installed or bonded prior to the start of commercial operation.

The project owner shall submit to the Director of the Kern County Planning Department for comment and to CPM for approval a landscaping and irrigation plan.

The Director of the Kern County Planning Department shall have 60 calendar days to review the landscaping and irrigation plan and provide written comments to the project owner. The project owner shall provide a copy of the Director of the Kern County Planning Department's written comments to the CPM for review and approval.

The project owner shall not implement the landscaping and irrigation plan until the project owner receives approval of the plan from the CPM. The planting must be completed by the start of commercial operation, and the planting must occur during the optimal planting season.

The project owner may submit to the CPM for approval an alternative to onsite landscaping for the project. The project owner may contribute the equivalent cost of the landscaping to the Kern County Parks and Recreation, a Kern County public school or other non-profit organization in the County of Kern acceptable to the Director of the Kern County Planning Department. The project owner's payment of the contribution shall be made prior to the start of commercial operation.

Verification: Prior to commercial operation and at least 45 days prior to installing the landscaping, the project owner shall provide a copy of the landscaping and irrigation plan to the Director of the Kern County Planning Department for review. The project owner shall allow the Director of the Kern County Planning Department at least 30 days to provide comment on the submitted landscaping and irrigation plan.

The project owner shall provide to the CPM a copy of the transmittal letter submitted to the Director of the Kern County Planning Department requesting their review of the submitted landscaping and irrigation plan.

If the CPM determines that the plan requires revision, the project owner shall provide to the CPM and the Director of the Kern County Planning Department a landscaping and irrigation plan with the specified revision(s) for review and to the CPM for final approval before the plan is implemented.

The project owner shall notify the CPM within seven days after completing installation of the landscaping and irrigation that the landscaping and irrigation is ready for inspection.

If the alternative to the planting of onsite landscaping is invoked by the project owner, the property owner shall provide to the CPM a copy of the receipt demonstrating payment to the Kern County Parks and Recreation, a Kern County public school or other non-profit organization in the County of Kern prior to the start of commercial operation.

REFERENCES

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Buhyoff, G.J., P.A. Miller, J.W. Roach, D. Zhou, and L.G. Fuller. 1994. An AI methodology for Landscape Visual Assessments. AI Applications Vol. 8, No 1

Caltrans2007a - California Department of Transportation website http://www.dot.ca.gov/

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Appendix VR-1

ENERGY COMMISSION VISUAL RESOURCE ANALYSIS EVALUATION CRITERIA

Energy Commission staff conducts a visual resource analysis according to Appendix G, “Environmental Checklist Form—Aesthetics,” California Environmental Quality Act (CEQA). The CEQA analysis requires that commission staff make a determination of impact ranging from “Adverse and Significant” to “Not Significant.”

Staff’s analysis is based on Key Observation Points or KOPs. KOPs are photographs of locations within the project area that are highly visible to the public — for example, travel routes; recreational and residential areas; and bodies of water as well as other scenic and historic resources.

Those photographs are taken to indicate existing conditions without the project and then modified to include a simulation of the project. Consequently, staff has a visual representation of the viewshed before and after a project is introduced and makes its analysis accordingly. Information about that analytical process follows.

VISUAL RESOURCE ANALYSIS WITHOUT PROJECT

When analyzing KOPs of existing conditions without the project, staff considers the following conditions: visual quality, viewer concern, visibility, number of viewers, duration of view. Those conditions are then factored into an overall rating of viewer exposure and viewer sensitivity. Information about each condition and rating follows.

Visual Quality

An expression of the visual impression or appeal of a given landscape and the associated public value attributed to the resource. Visual quality is rated from *high* to *low*. A high rating is generally reserved for landscapes viewers might describe as picture-perfect.

Landscapes rated high generally are memorable because of the way the components combine in a visual pattern. In addition, those landscapes are free from encroaching elements, thus retaining their visual integrity. Finally, landscapes with high visual quality are visually coherent and harmonious when each element is considered as part of the whole. On the contrary, landscapes rated *low* are often dominated by visually discordant human alterations.

Viewer Concern

Viewer concern represents the reaction of a viewer to visible changes in the viewshed — an area of land visible from a fixed vantage point. For example, viewers have a high expectation for views formally designated as a scenic area or travel corridor as well as for recreational and residential areas. Viewers generally expect that those views will be preserved. Travelers on highways and roads, including those in agricultural areas, are generally considered to have moderate viewer concerns and expectations.

However, viewers tend to have low-to-moderate viewer concern when viewing commercial buildings. Industrial uses typically have the lowest viewer concern. Regardless, the level of concern could be lower if the existing landscape contains discordant elements. In addition, some areas of lower visual quality and degraded visual character may contain particular views of substantially higher visual quality or interest to the public.

Visibility

Visibility is a measure of how well an object can be seen. Visibility depends on the angle or direction of views; extent of visual screening; and topographical relationships between the object and existing homes, streets, or parks. In that sense, visibility is determined by considering any and all obstructions that may be in the sightline—trees and other vegetation; buildings; transmission poles or towers; general air quality conditions such as haze; and general weather conditions such as fog.

Number of Viewers

Number of viewers is a measure of the number of viewers per day who would have a view of the proposed project. *Number of viewers* is organized into the following categories: residential according to the number of residences; motorist according to the number of vehicles; and recreationists.

Duration of View

Duration of view is the amount of time to view the site. For example, a high or extended view of a project site is one reached across a distance in two minutes or longer. In contrast, a low or brief duration of view is reached in a short amount of time—generally less than ten seconds.

Viewer Exposure

Viewer exposure is a function of three elements previously listed, *visibility*, *number of viewers*, and *duration of view*. Viewer exposure can range from a *low* to *high*. A partially obscured and brief background view for a few motorists represents a low value; and unobstructed foreground view from a large number of residences represents a high value.

Visual Sensitivity

Visual sensitivity is comprised of three elements previous listed, *visual quality*, *viewer concern*, and *viewer exposure*. Viewer sensitivity tends to be higher for homeowners or people driving for pleasure or engaged in recreational activities and lower for people driving to and from work or as part of their work.

VISUAL RESOURCE ANALYSIS WITH PROJECT

Visual resource analyses with photographic simulations of the project involve the elements of contrast, dominance, view blockage, and visual change. Information about each element follows.

Contrast

Contrast concerns the degree to which a project's visual characteristics or elements (form, line, color, and texture) differ from the same visual elements in the existing landscape. The degree of contrast can range from *low* to *high*. A landscape with forms, lines, colors, and textures similar to those of a proposed energy facility is more visually absorbent; that is, more capable of accepting those characteristics than a landscape in which those elements are absent.[3] Generally, visual absorption is inversely proportional to visual contrast.

Dominance

Dominance is a measure of (a) the proportion of the total field of view occupied by the field; (b) a feature's apparent size relative to other visible landscape features; and (c) the conspicuousness of the feature due to its location in the view.

A feature's level of dominance is lower in a panoramic setting than in an enclosed setting with a focus on the feature itself. A feature's level of dominance is higher if it is (1) near the center of the view; (2) elevated relative to the viewer; or (3) has the sky as a backdrop. As the distance between a viewer and a feature increases, its apparent size decreases; and consequently, its dominance decreases. The level of dominance ranges from *low* to *high*.

View Blockage

The extent to which any previously visible landscape features are blocked from view constitutes view disruption. The view is also disrupted when the continuity of the view is interrupted. When considering a project's features, higher quality landscape features can be disrupted by lower quality project features, thus resulting in adverse visual impacts. The degree of view disruption can range from *none* to *high*.

Visual Change

Visual change is a function of *contrast*, *dominance*, and *view disruption*. Generally, *contrast* and *dominance* contribute more to the degree of visual change than does *view disruption*.

[3] Typically, the Energy Commission does not consider texture in its visual analyses.

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Appendix VR-2

Visible Plume Modeling Analysis - William Walters

INTRODUCTION

The following provides the assessment of the Beacon Solar Energy Project (Beacon or BSEP) cooling tower exhaust stack visible plumes. Staff completed a modeling analysis for the applicant’s proposed unabated cooling tower design based on data provided by the applicant.

PROJECT DESCRIPTION

The proposed project is a thermal solar design that requires cooling to condense the steam that is recycled through the power block. The applicant has proposed an eleven-cell mechanical-draft cooling tower for project cooling. The applicant has not proposed to use any methods to abate visible plumes from the cooling towers.

The applicant has also proposed two small (30 MMBtu/hr) boilers that will be used for daily start-up and for freeze protection. These boilers will be operated for a maximum of 1,000 hours per year. During cold weather periods, such as their use during start-up and for freeze protection in winter these boilers are likely to have visible plumes. However, due to their limited use and small size the boiler plumes are not believed to create a potentially significant visual impact and are not assessed further in this analysis.

VISIBLE PLUME MODELING METHODS

PLUME FREQUENCY AND DIMENSION MODELING

The Combustion Stack Visible Plume (CSVP) model was used to estimate plume frequency and plume dimensions for the cooling tower exhaust. This model provides conservative estimates of both plume frequency and plume size. This model uses hourly cooling tower exhaust parameters and hourly ambient condition data to determine the plume frequency. This model is based on the algorithms of the Industrial Source Complex model (Version 2), that determine temperatures at the plume centerline, but this model does not incorporate building downwash.

The modeling method combines the cooling tower cell exhausts into an equivalent single stack. This method may overestimate cooling tower plume size (particularly height) during plume hours with higher winds perpendicular to the length of the tower due to little cell interaction and the potential for building downwash, but will be more accurate during low wind and calm periods when the exhausts from the cooling tower cells will combine into one coherent body. Wind speeds are set to 1 m/s during calm hours in the modeling analysis.

CLOUD COVER DATA ANALYSIS METHOD

A plume frequency of 20 percent of seasonal (November through April) daylight no rain/fog high visual contrast (i.e. "clear") hours is used to determine potential plume impact significance. The methodology used to determine high visual contrast hours is provided below:

> The Energy Commission has identified a "clear" sky category during which plumes have the greatest potential to cause adverse visual impacts. For this project the meteorological data set[4] used in the analysis categorizes total sky cover as "clear", "scattered", "broken", "overcast", "partially obscured", and obscured". For the purpose of estimating the high visual contrast hours staff has included in the "Clear" category a) all hours with total sky cover defined as "clear" plus b) half of the non-obscured hours with unlimited ceiling height (i.e. hours with a sky opacity equal to or less than 50%). The rationale for including these two components in this category is as follows: a) plumes typically contrast most with sky under clear conditions and b) for a substantial portion of the time when total sky cover is not clear or obscured the opacity of the sky cover is relatively low (equal to or less than 50%), and these clouds do not substantially reduce contrast with plumes. Staff has estimated that approximately half of the hours with sky opacity of less than 50% can be considered high visual contrast hours and are included in the "clear" sky definition.

If it is determined that the seasonal daylight clear hour plume frequency is greater than 20 percent then plume dimensions are calculated, and a significance analysis of the plumes is included in the Visual Resources section of the Staff Assessment.

COOLING TOWER VISIBLE PLUME MODELING ANALYSIS

COOLING TOWER DESIGN AND OPERATING PARAMETERS

The cooling tower design characteristics were determined through a review of the applicant's AFC (BSEP 2008a), the air quality and visible plume modeling files (BSEP 2008b), and additional data provided by the applicant to estimate daily and seasonal cooling tower operations (BS 2009). The applicant's cooling tower physical design parameters are presented in **Visible Plume Table 1**.

Visible Plume Table 1
Cooling Tower Physical Design Parameters

Parameter	Cooling Tower Design Parameters
Number of Cells per Tower	11 Cells (Linear Design)
Cell Height	44.3 feet (13.5 meters)
Cell Stack Diameter	28 feet (8.53 meters)
Tower Housing Length	595 feet (181.3 meters)
Tower Housing Width	48.6 feet (14.8 meters)

Source: BSEP 2008a and BSEP 2008b.

[4] This analysis uses three years of meteorological data (2002 through 2004) from the Mojave Poole Street meteorological data site that was obtained and processed by the applicant from the U.S. EPA Air Quality System Meteorological Data System, and relative humidity data from Fox Field in Lancaster.

The applicant provided estimated average heat rejection data for each hour of each month (BS 2009). The applicant also noted that at a minimum one half of the cells, assumed by staff to be 5 of 11, would have fans operating. However, the heat rejection turndown is a much greater value than one-half, which during very cold periods would likely cause freezing problems in the cooling tower if more cell fans are not turned off. Therefore, to be conservative, staff has assigned an average heat rejection of 39 MW of heat rejection to determine the number of cells operating on average for each hour of each month. The applicant's heat rejection basis and staff's cooling tower cell operating assumptions are provided in **Visible Plume Tables 2** and **3**, respectively.

Visible Plume Table 2
Cooling Tower Average Heat Rejection, MW

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
6.5	0	0	0	67	140	207	149	59	0	0	0	0
7.5	0	0	122	311	343	396	347	309	275	125	0	0
8.5	55	143	280	379	387	425	388	389	394	277	142	58
9.5	158	231	328	410	389	426	408	412	406	292	222	144
10.5	176	232	331	414	393	428	409	404	395	290	216	160
11.5	171	222	317	416	412	428	409	406	377	271	202	147
12.5	174	220	321	398	406	411	420	397	372	271	198	153
13.5	199	235	323	402	405	429	415	396	368	298	210	176
14.5	222	250	325	406	392	405	423	385	368	313	225	192
15.5	205	255	314	378	384	404	409	358	323	287	176	136
16.5	66	159	252	362	360	372	371	322	243	116	0	0
17.5	0	0	65	163	196	257	258	171	71	0	0	0
18.5	0	0	0	0	0	59	59	0	0	0	0	0

Source: BS 2009.

Visible Plume Table 3
Staff's Assumed Number of Operating Cooling Tower Cells

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
6.5	0	0	0	2	4	6	4	2	0	0	0	0
7.5	0	0	4	8	9	11	9	8	8	4	0	0
8.5	2	4	8	10	10	11	10	10	11	8	4	2
9.5	5	6	9	11	10	11	11	11	11	8	6	4
10.5	5	6	9	11	11	11	11	11	11	8	6	5
11.5	5	6	9	11	11	11	11	11	10	7	6	4
12.5	5	6	9	11	11	11	11	11	10	7	6	4
13.5	6	7	9	11	11	11	11	11	10	8	6	5
14.5	6	7	9	11	11	11	11	10	10	9	6	5
15.5	6	7	9	10	10	11	11	10	9	8	5	4
16.5	2	5	7	10	10	10	10	9	7	3	0	0
17.5	0	0	2	5	6	7	7	5	2	0	0	0
18.5	0	0	0	0	0	2	2	0	0	0	0	0

Source: Staff Analysis

Staff presents the following exhaust assumptions for three specified ambient conditions in **Visible Plume Table 4** that give the exhaust temperatures assumed by staff's heat balance at three different ambient conditions.

Visible Plume Table 4
Cooling Tower Exhaust Temperatures

Case	Inlet Air Ambient Condition	Exhaust Temperature
1	30°F, 84% RH	72.15°F
2	65°F, 27% RH	81.42°F
3	100°F, 16% RH	99.15°F

Source: Staff heat balance.

The cooling tower operation for this project is significantly different than the dozens of cooling towers evaluated for siting cases from 2001 to present. Specifically, the heat rejection load to the cooling tower is specifically related to the sun angle (time of day and year) that impacts the total power production capacity of the facility. Therefore, the cooling tower operation starts at low heat rejection loads each morning and building until the afternoon when the heat rejection load drops as the sun sets. Staff has attempted to mimic, in a simple way, the complex operating profile of the cooling tower exhaust modeling inputs. Additionally, the hourly cooling tower exhaust conditions are interpolated for the hourly ambient conditions (temperature and relative humidity) based on the assumed heat rejection for each operating cooling tower cell.

COOLING TOWER VISIBLE PLUME MODELING RESULTS

Visible Plume Table 5 provides the CSVP model visible plume frequency results for daytime operations using a three-year (2002 to 2004) meteorological data set compiled from a mixture of Mojave Poole Street and Fox Field Lancaster sources.

Visible Plume Table 5
Predicted Hours with Cooling Tower Visible Plumes
Mojave/Lancaster 2002-2004 Meteorological Data

Case	Available (hr)	Plume (hr)	Percent
Daytime	12,117	2,086	17.2%
Seasonal Daytime	5,409	1,865	34.5%
Seasonal Daytime No Rain/No Fog	5,296	1,774	33.5%
Seasonal Daytime Clear	4,689	1,425	30.4%

*Seasonal conditions occur during November through April.

The results noted above are based on the data and assumptions shown in **Visible Plume Tables 2** through **4**, and do not include night time operation as the heat load for the cooling tower is a function of the solar radiation.

Since the plume frequencies remain over 20% of the seasonal daylight clear hours the corresponding plume dimensions were estimated. The plume dimensions are estimated by the CSVP model and presented in **Visible Plume Table 6**.

Visible Plume Table 6
Predicted Cooling Tower Visible Plume Dimensions

	Cooling Tower Seasonal "Clear" Hours Plume Dimensions in Meters (feet)		
Percentile	**Length**	**Height**	**Width**
5%	63.6 (209)	142.7 (468)	37.5 (123)
10%	37.2 (122)	92.3 (303)	27.1 (89)
15%	30.2 (99)	57.4 (188)	24.3 (80)
20%	**26.1 (86)**	**33.9 (111)**	**23.5 (77)**
25%	20.9 (69)	26.4 (87)	22.2 (73)
30%	8.1 (27)	17.7 (58)	16.3 (53)

Results include the cooling tower stack height of 13.5 meters (44.3 feet), see **Visible Plume Table 1**.

These plume sizes are not dissimilar in magnitude to those predicted by the applicant using the SACTI model (BS 2008b), considering the differences in approach, with the exception that the SACTI model groups the met data and does not model calm hours which will cause some underestimation of maximum plume height during worst case hourly conditions.

APPLICANT'S PLUME ANALYSIS

The applicant prepared a plume modeling analysis using the Seasonal/Annual Cooling Tower Impact (SACTI) model. Due to the way the SACTI model over simplifies the modeling by only allowing one operating case to be modeled at a time and its grouping of the hourly meteorological data into a couple dozen cases, among a few other significant issues, staff does not use this model for plume frequency and size prediction. However, staff has reviewed the applicant's plume modeling files and found several input issues that would impact the predicted plume sizes. Those input issues include:

- The hourly profile of the heat rejection and seasonal profile of the heat rejection were not incorporated into the model, which would overestimate the potential plume sizes and plume ground fogging events.
- The gas flow rate of 7618.3 kg/s was too high in comparison with that used in the air quality modeling which would be approximately 6,700 kg/s. However, the applicant has indicated that this flow rate is correct for the maximum heat rejection rate (BS 2009).
- The heat rejection value of 451.2 MW was too high considering that the heat balance in the AFC provides a value of 438.4 MW. The applicant indicates that this peak heat rejection rate is correct regardless of the energy balance data in the AFC (BS 2009).
- The resolution of the results was low due to the spacing for data output (i.e. plume length and height output was spaced at 100 meter intervals rather than at 10 or 25 meter intervals.
- The temperature for 100°F+ hours dropped the initial 1 in the meteorological data file, where 102 hours were impacted in the daytime meteorological data file. However, if anything this would cause over prediction of summer plumes.

- Staff considers a six month seasonal period November through April to determine initial potential for significance, the applicant provided season of year results (i.e. winter, spring, etc.).
- There were input spacing issues that caused the first digit in some of the distances from tower to be truncated, which caused a minor break in the results.

The issue with the greatest impact on the interpretation of the results is the reduced output data spacing. In general, the applicant's SACTI estimated plume size results were somewhat smaller than what staff would predict using the heat rejection and air flow as supplied with the AFC, where the applicant stands by their SACTI input values regardless of the other supplied AFC data. However, staff agrees in general with the plume sizes and frequencies determined by the applicant using the SACTI model. However, staff uses the CSVP model, which provides hourly visible plume results based on actual hourly ambient data, to provide hourly plume results.

GROUND FOGGING ANALYSIS

Staff also reviewed the applicant's ground fogging modeling analysis and separately modeled the plumes using the Seasonal/Annual Cooling Tower Impact (SACTI) model. Ground fogging was predicted a few hours per year on average, but no ground fogging was predicted beyond 500 meters, or past the project fence line. Therefore, no potential for ground based traffic safety impacts on public roads are predicted for cooling tower operation.

CONCLUSIONS

Visible water vapor plumes from the proposed Beacon cooling tower could occur more than 20 percent of seasonal daylight clear hours depending on facility operation. Therefore, further visual impact analysis of worst-case plume frequencies and plume sizes has been completed.

Due to the small size and limited operation significant visible water vapor plumes are not expected from the two small BSEP boilers.

REFERENCES

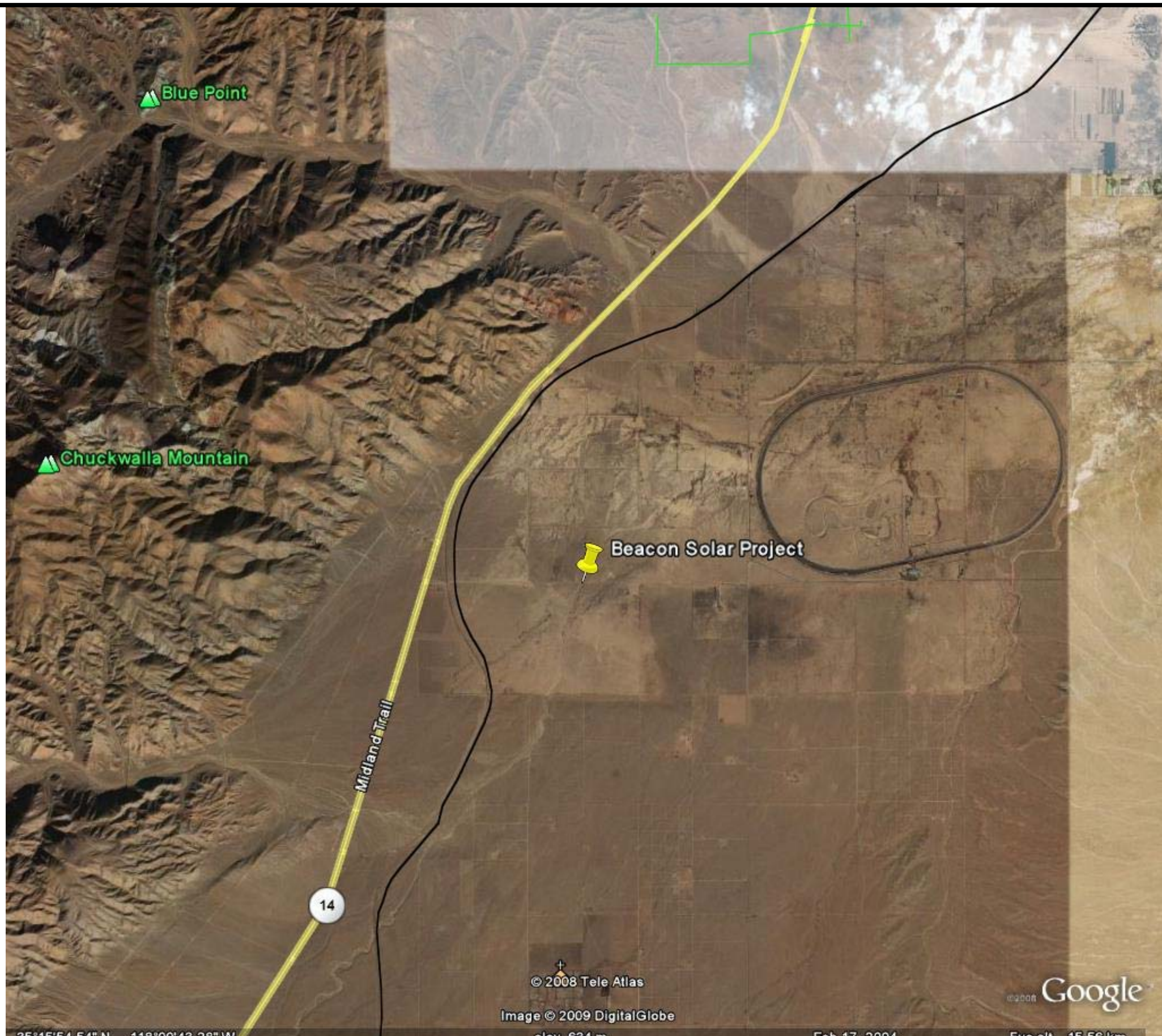
BS 2008a - FPL Energy/M. O'Sullivan (tn 45646). Application for Certification, dated 03/13/08. Submitted to CEC/Docket Unit on 03/14/08.

BS 2008b - FPL Energy/M. O'Sullivan (tn 45647). Air Modeling Files. Submitted to CEC/Docket Unit on 03/14/08.

BS 2009 - FPL Energy/M. O'Sullivan. Cooling tower heat duty information from WorleyParsons and cooling tower operating information and notes on SACTI analysis by AECOM. Submitted to CEC/Docket Unit on 01/26/09.

VISUAL RESOURCES - FIGURE 1

Beacon Solar Energy Project - Aerial View of Beacon Solar Energy Project and Vicinity



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: Google Earth

VISUAL RESOURCES - FIGURE 2
Beacon Solar Energy Project - Existing View of the Project Site

1.

2.

3.

4.

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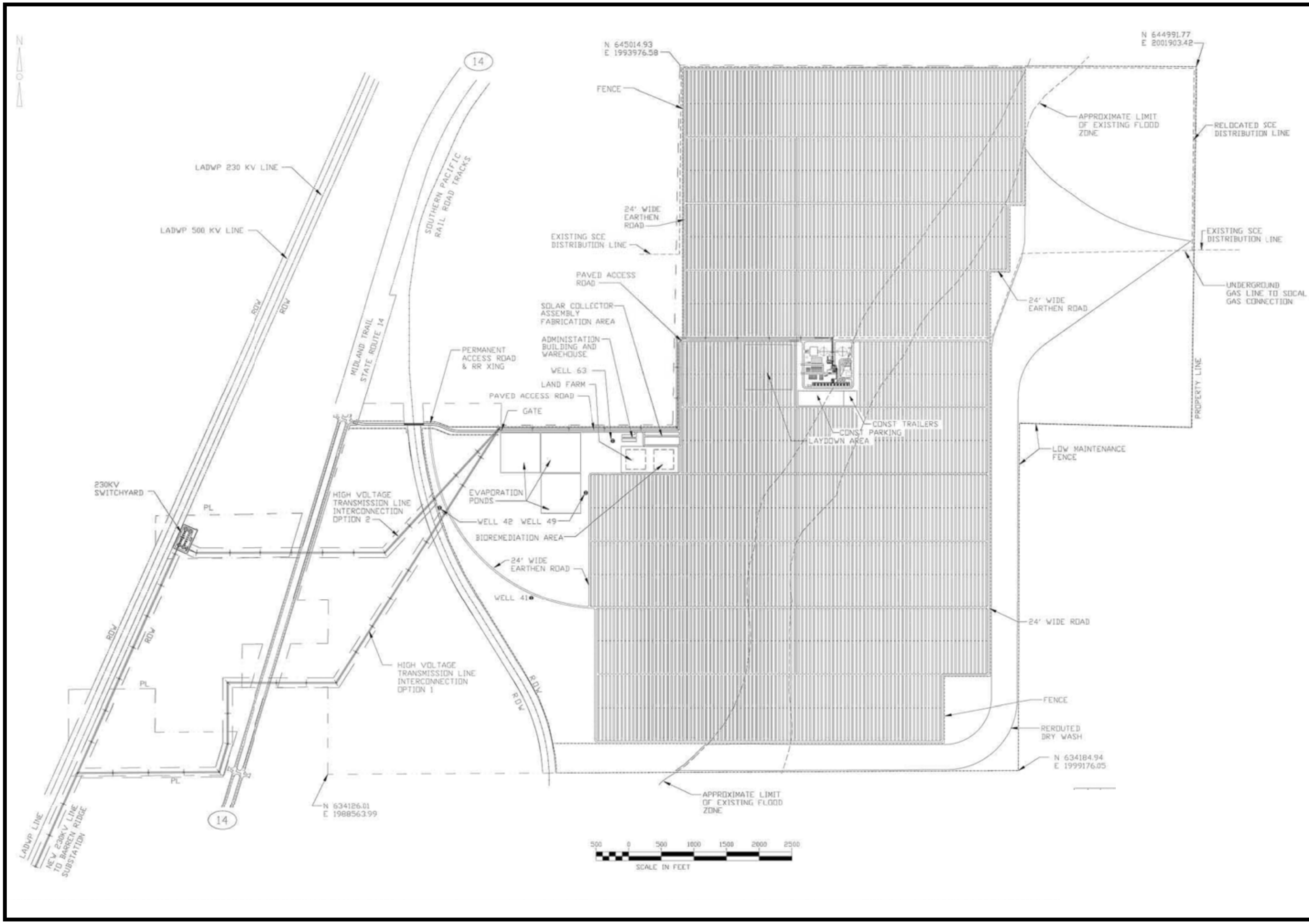
SOURCE: Staff Photos

VISUAL RESOURCES - FIGURE 3
Beacon Solar Energy Project - General Arrangement Site Plan



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SOURCE: AFC Figure 2-4

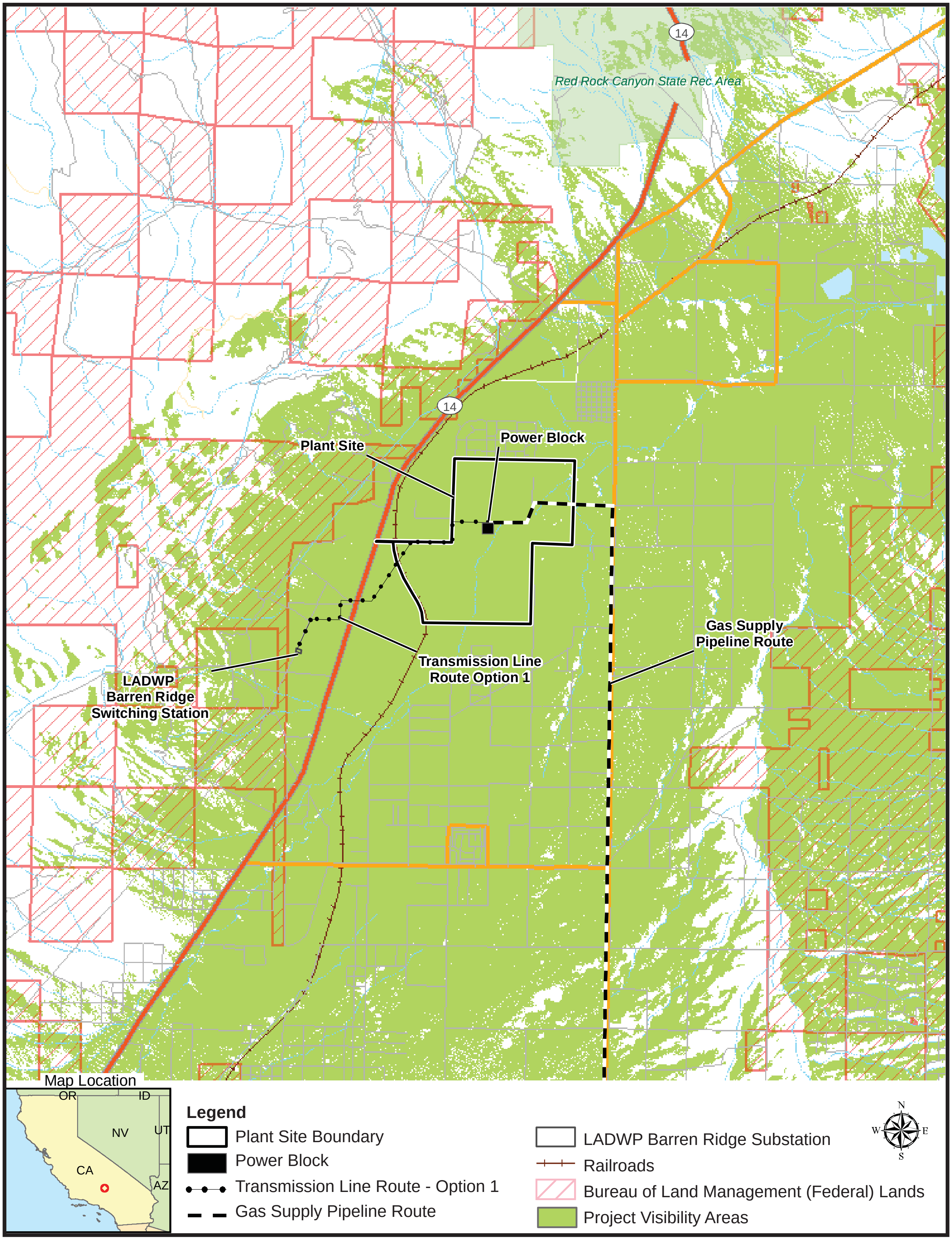
VISUAL RESOURCES - FIGURE 4

Beacon Solar Energy Project - SEGES Kramer Junction Project

SOURCE:

VISUAL RESOURCES - FIGURE 5

Beacon Solar Energy Project - Regional Visibility of the BSEP



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-1a

VISUAL RESOURCES - FIGURE 6

Beacon Solar Energy Project - View of Existing Residences North of Project Site (Rancho Seco)

1.

2.

3.

4.

SOURCE: Staff Photos

VISUAL RESOURCES - FIGURE 7

Beacon Solar Energy Project - View of closest Residence West of Project Site along SR - 14

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SOURCE: Staff Photo

Beacon Solar Energy Project - View towards the Honda Proving Center Oval Track from Entrance and View 1.5 miles South of the Proving Center Entrance

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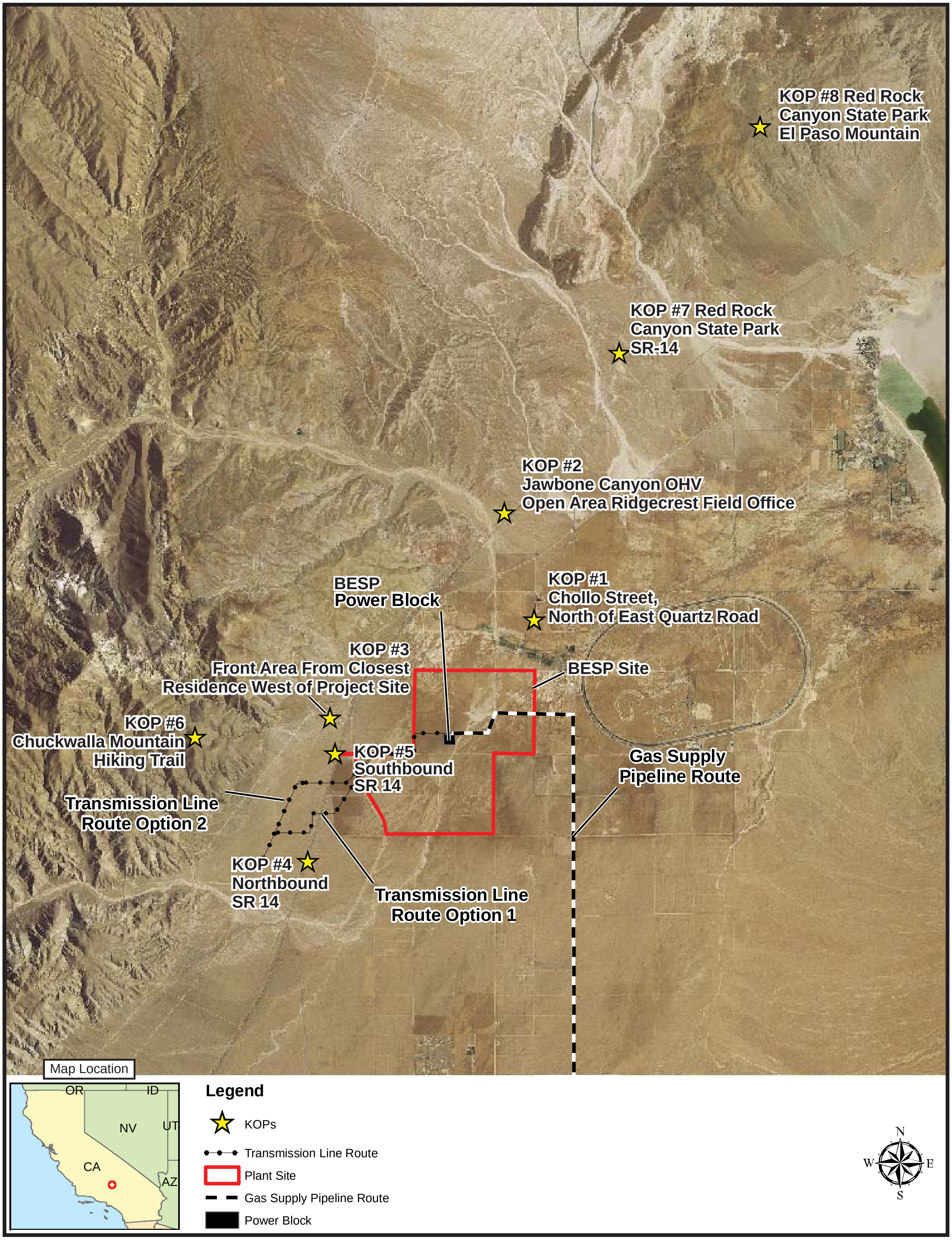
SOURCE: Staff Photo

VISUAL RESOURCES - FIGURE 9

Beacon Solar Energy Project - Key Observation Points



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SOURCE: AFC Figure 5.15-3

VISUAL RESOURCES - FIGURE 10

Beacon Solar Energy Project - KOP 1- Existing view toward the Project Site from Chollo Street in Rancho Seco

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SOURCE: AFC Figure 5.15-4a

VISUAL RESOURCES - FIGURE 11a

Beacon Solar Energy Project - KOP 1- Simulation of the Proposed Project's Publicly Visible Structures after Completion with Transmission Option One

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SOURCE: AFC Figure 5.15-4b

VISUAL RESOURCES - FIGURE 11b

Beacon Solar Energy Project - KOP 1- Simulation of the Proposed Project's Publicly Visible Structures after Completion with Transmission Option Two

SOURCE: AFC Figure 5.15-4c

VISUAL RESOURCES - FIGURE 12

Beacon Solar Energy Project - KOP 2 - Existing view toward the Project Site from the Public Parking Area of the Jawbone Canyon BLM Ridgecrest Office

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-5a

VISUAL RESOURCES - FIGURE 13a

Beacon Solar Energy Project - KOP 2 - Simulation of the Proposed Project's Publicly Visible Structures after Completion with Transmission Option One

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-5b

JANUARY 2009

VISUAL RESOURCES - FIGURE 13b

Beacon Solar Energy Project - KOP 2 - Simulation of the Proposed Project's Publicly Visible Structures after Completion with Transmission Option Two

VISUAL RESOURCES

SOURCE: AFC Figure 5.15-5c

VISUAL RESOURCES - FIGURE 13b

Beacon Solar Energy Project - KOP 2 - Simulation of the Proposed Project's Publicly Visible Structures after Completion with Transmission Option Two

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-5c

VISUAL RESOURCES - FIGURE 14

Beacon Solar Energy Project - KOP 3 - Existing view toward the Project Site from the Highway Apron serving the closest Residence West of the Project Site

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-8a

VISUAL RESOURCES - FIGURE 15

Beacon Solar Energy Project - KOP 3 - Simulation of the Proposed Project's Publicly Visible Structures after Completion of Construction showing both Transmission Line Options

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-8b

VISUAL RESOURCES - FIGURE 16

Beacon Solar Energy Project - KOP 4 - Existing view from Northbound SR 14 towards Project Site

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-6a

VISUAL RESOURCES - FIGURE 17

Beacon Solar Energy Project - KOP 4 - Simulation of the Proposed Project's Visible Structures after Completion of Construction with both Overhead Transmission Line Options

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-6b

VISUAL RESOURCES - FIGURE 18

Beacon Solar Energy Project - KOP 5 - Existing view of Southbound SR 14 looking towards the location of the Project's Proposed Overhead Transmission Line crossing of the Highway

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-7a

VISUAL RESOURCES - FIGURE 19a

Beacon Solar Energy Project - KOP 5 - Simulation of the Proposed Project's Publicly Visible Structures after Completion with Overhead Transmission Option One

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-7b

VISUAL RESOURCES - FIGURE 19b

Beacon Solar Energy Project - KOP 5 - Simulation of the Proposed Project's Publicly Visible Structures after Completion with Overhead Transmission Option Two

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-7c

VISUAL RESOURCES - FIGURE 20

Beacon Solar Energy Project - KOP 6 - Existing view from the Public Hiking Trail to Chuckwalla Mountain towards the Project Site

SOURCE: AFC Figure 5.15-9a

VISUAL RESOURCES - FIGURE 21a

Beacon Solar Energy Project - KOP 6 - Simulation of the Proposed Project's Publicly Visible Structures after Completion with Overhead Transmission Option One

SOURCE: AFC Figure 5.15-9b

VISUAL RESOURCES - FIGURE 21b

Beacon Solar Energy Project - KOP 6 - Simulation of the Proposed Project's Publicly Visible Structures after Completion with Overhead Transmission Option Two

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, JANUARY 2009

SOURCE: AFC Figure 5.15-9c

WASTE MANAGEMENT

Ellie Townsend-Hough

SUMMARY OF CONCLUSIONS

Staff concludes that management of the waste generated during demolition, construction and operation of the Beacon Solar Energy Project (BSEP) would not result in any significant adverse impacts, and would comply with applicable LORS, if the waste management practices and mitigation measures proposed in the BSEP AFC and staff's proposed conditions of certification are implemented.

INTRODUCTION

This Preliminary Staff Assessment (PSA) presents an analysis of issues associated with managing wastes generated from constructing and operating the proposed BSEP project and any hazardous wastes already existing on site because of past activities. Staff has evaluated the proposed waste management plans and mitigation measures designed to reduce the risks and environmental impacts associated with handling, storing, and disposing of project-related hazardous and non-hazardous wastes. The technical scope of this analysis encompasses solid wastes existing on site, and those generated during facility construction and operation. Wastewater issues are more fully discussed in the **Soil and Water Resources** section of this document. Additional information related to waste management may also be covered in the **Worker Safety** and **Hazardous Materials Management** sections of this document.

Energy Commission staff's objectives in its waste management analysis are to ensure that:

- the management of wastes would be in compliance with all applicable laws, ordinances, regulations, and standards (LORS). Compliance with LORS ensures that wastes generated during the construction and operation of the proposed project would be managed in an environmentally safe manner;
- the disposal of project wastes would not result in significant adverse impacts to existing waste disposal facilities; and
- during project operation, the site is managed such that contaminants would not pose a significant risk to humans or to the environment.

LAWS, ORDINANCES, REGULATION, AND STANDARDS

The following framework of federal, state, and local environmental LORS exists to ensure the safe and proper management of hazardous wastes from generation to disposal in order to reduce the risks of accidents that might impact worker and public health and the environment.

WASTE MANAGEMENT Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
RCRA, Subtitle C and D, 42 USC § 6901 to 6992k, and Section 6.12.2.1	Establishes requirements for the management of solid wastes (including hazardous wastes), landfills, underground storage tanks, and certain medical wastes. The statute also addresses program administration, implementation and delegation to states, enforcement provisions and responsibilities, as well as research, training, and grant funding provisions. RCRA Subtitle C establishes provisions for the generation, storage, treatment, and disposal of hazardous waste, including requirements addressing: • Generator record keeping practices that identify quantities of hazardous wastes generated and their disposition; • Waste labeling practices and use of appropriate containers; • Use of a manifest when transporting wastes; • Submission of periodic reports to the United States Environmental Protection Agency (USEPA) or other authorized agency; and • Corrective action to remediate releases of hazardous waste and contamination associated with RCRA-regulated facilities. RCRA Subtitle D establishes provisions for the design and operation of solid waste landfills. RCRA is administered at the federal level by USEPA and its ten regional offices. The Pacific Southwest regional office (Region 9) implements USEPA programs in California, Nevada, Arizona, and Hawaii.
40 CFR 260, *et seq.*	Contains regulations promulgated by the EPA to implement the requirements of RCRA as described above. Characteristics of hazardous waste are described in terms of ignitability, corrosivity, reactivity, and toxicity, and specific types of waste are listed.
Federal CWA, 33 USC § 1251 *et seq.*	Controls discharge of wastewater to the surface waters of the U.S.
State	
California Integrated Waste Management Act, Public Resources Code § 40000 *et seq.*	Provides an integrated statewide system of solid waste management by coordinating state and local efforts in source reduction, recycling, and land disposal safety. Counties are required to submit Integrated Waste Management Plans to the state.
Porter- Cologne Water Quality Control Act of 1998, Water Code § 13000 *et seq.*	Controls discharge of wastewater to surface waters and groundwaters of California.
22 CCR § 66262.34	Regulates accumulation periods for hazardous waste generators. Typically, hazardous waste cannot be stored onsite for more than 90 days.
California Health and Safety Code §	Creates the framework under which hazardous wastes must be managed in California. It mandates the State Department of Health Services (now

25100 *et seq.* (Hazardous Waste Control Act of 1972, as amended)	the Department of Toxic Substances Control (DTSC), under the California Environmental Protection Agency (CalEPA), to develop and publish a list of hazardous and extremely hazardous wastes and to develop and adopt criteria and guidelines for the identification of such wastes. It also requires hazardous waste generators to file notification statements with Cal EPA and create a manifest system to be used when transporting such wastes.
Title 27, California Code of Regulations, §15100 et seq. (Unified Hazardous Waste and Hazardous Materials Management Regulatory Program)	Consolidates, coordinates, and makes consistent portions of the following six existing programs: • Hazardous Waste Generators and Hazardous Waste Onsite Treatment; • Underground Storage Tanks; • Hazardous Material Release Response Plans and Inventories; • California Accidental Release Prevention Program; • Aboveground Storage Tanks (spill control and countermeasure plan only); • Uniform Fire Code Hazardous Material Management Plans and Inventories; The statute requires all counties to apply to the CalEPA Secretary for the certification of a local unified program agency.
Title 14, California Code of Regulations, §17200 et seq. (Minimum Standards for Solid Waste Handling and Disposal)	Sets forth minimum standards for solid waste handling and disposal, guidelines to ensure conformance of solid waste facilities with county solid waste management plans and the California Integrated Waste Management Board, as well as enforcement and administration provisions.
Title 8 California Code of Regulations §1529 and §5208	Requires the proper removal of asbestos- containing materials and are enforced by California Occupational Safety and Health Administration (Cal OSHA).
Local	
Health and Safety: Kern County Ordinance, Title 8	Establish requirements for the use, generation, storage, and disposal of hazardous materials and wastes within Kern County.

SETTING

The proposed BSEP is a 250 megawatt (MW) concentrated solar electric generating facility (BS 2008a, page.2-1). The facility will be located on approximately 2,012 acres of land, adjacent to California State Route 14 just north of the community of California City, in an unincorporated area of eastern Kern County, California in the western edge of the Mojave Desert (BS 2008a, page 2-1).

The solar plant is made up of parabolic trough solar thermal technology producing electrical power using a steam turbine generator that is fed from a solar steam generator. The solar steam generator receives heated heat transfer fluid (HTF) from the parabolic trough solar collectors that collect energy from the sun. Natural gas is used to fuel two auxiliary boilers which will reduce plant start-up time and will supply steam for freeze protection for the HTF (BS 2008a, page 2-1).

Natural gas for the project will be obtained by a new 17.6-mile, eight-inch gas pipeline that will be connected to an existing Southern California Gas company pipeline. The pipeline will be routed along portions of Neuralia Road and California City Boulevard in Kern County, California. Fifty-three percent of the pipeline route is surrounded by vacant undeveloped desert (DB 2008j, page 2.2). As shown on **WASTE MANGEMENT Figure 1**, the applicant is proposing two alternative transmission line routes: a 3.5-mile route and in the alternative a 2.3-mile route. The project will only require that one of the proposed 230 kV transmission line routes to be constructed and connected to the Barren Ridge Switching Station (BS 2008a, page 2.-1).

The project will also use three double lined evaporation ponds. The ponds require a total of 25 acres. In the AFC, the applicant proposed using a bioremediation/land farm to treat soil that may be contaminated from potential HTF spills. The California Department of Toxic Substances Control issued a letter on April 4, 1995 stating that HTF contaminated soil "posed an insignificant hazard and [the DTSC] classifies the waste as nonhazardous pursuant to 22CCR section 66260.200(f)." Therefore, the bioremediation unit was eliminated and the land treatment unit will be maintained at the project site (DB 2008d, Data Response 57).

Hazardous and non-hazardous solid and liquid waste, including wastewater, would be generated at the BSEP project during construction and operation of the power plant. Waste would be recycled where practical and non-recyclable waste would be deposited in a Class III landfill. The hazardous waste generated during this phase of the project would consist of electrical equipment, used oils, universal wastes, solvents, and empty hazardous waste containers (BS 2008a, section 5.16.3.1). Universal wastes are hazardous wastes that contain mercury, lead, cadmium, copper, and other substances hazardous to human and environmental health. Examples of universal wastes are batteries, fluorescent tubes, and electronic devices.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

This waste management analysis addresses: a) existing project site conditions and the potential for contamination associated with prior activities on or near the project site, and b) the impacts from the generation and management of wastes during project construction and operation.

For any site in California proposed for the construction of a power plant, the applicant must provide documentation about the nature of any potential or existing releases of hazardous substances or contamination at the site. If potential or existing releases or contamination at the site are identified, the significance of the release or contamination would be determined by site-specific factors, including, but not limited to: the amount and concentration of contaminants or contamination; the proposed use of the area where the contaminants/contamination is found; and any potential pathways for workers, the public, or sensitive species or environmental areas to be exposed to the contaminants. Any unmitigated contamination or releases of hazardous substances that pose a risk to human health or environmental receptors would be considered significant by Energy Commission staff.

As a first step in documenting existing site conditions, the Energy Commission's power plant site certification regulations require that a Phase I Environmental Site Assessment (ESA) be prepared[1] and submitted as part of an AFC. The Phase I ESA is conducted to identify any conditions indicative of releases and threatened releases of hazardous substances at the site and to identify any areas known to be contaminated (or a source of contamination) at or near the site.

In general, the Phase I ESA uses a qualified environmental professional to conduct inquiries into past uses and ownership of the property, research hazardous substance releases and hazardous waste disposal at the site and within a certain distance of the site, and visually inspect the property, making observations about the potential for contamination and possible areas of concern. After conducting all necessary file reviews, interviews, and site observations, the environmental professional then provides findings about the environmental conditions at the site. In addition, since the Phase I ESA does not include sampling or testing, the environmental professional may also give an opinion about the potential need for any additional investigation. Additional investigation may be needed, for example, if there were significant gaps in the information available about the site, an ongoing release is suspected, or to confirm an existing environmental condition.

If additional investigation is needed to identify the extent of possible contamination, a Phase II ESA may be required. The Phase II ESA usually includes sampling and testing of potentially contaminated media to verify the level of contamination and the potential for remediation at the site.

In conducting its assessment of the proposed project, Energy Commission staff will review the project's Phase I ESA and work with the appropriate oversight agencies as necessary to determine if additional site characterization work is needed and if any mitigation is necessary at the site to ensure protection of human health and the environment from any hazardous substance releases or contamination identified.

Regarding the management of project-related wastes generated during construction and operation of the proposed project, staff reviewed the applicant's proposed solid and hazardous waste management methods to determine whether or not the proposed waste management methods are consistent with the LORS identified for waste disposal and recycling. The federal, state, and local LORS represent a comprehensive regulatory system designed to protect human health and the environment from impacts associated with management of both non-hazardous and hazardous wastes. Absent any unusual circumstances, staff considers project compliance with LORS to be sufficient to ensure that no significant impacts would occur as a result of project waste management.

[1] Title 20, California Code of Regulations, section 1704(c) and Appendix B, section (g)(12)(A). Note that the Phase I ESA must be prepared according to American Society for Testing and Materials protocol or an equivalent method agreed upon by the applicant and the Energy Commission staff.

Staff then reviewed the capacity available at off-site treatment and disposal sites and determined whether or not the proposed power plant's waste would have a significant impact on the volume of waste a facility is permitted to accept. Staff used a waste volume threshold equal to 10 percent of a disposal facility's remaining permitted capacity to determine if the impact from disposal of project wastes at a particular facility would be significant.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Existing Site Conditions

The facility will be located on approximately 2,012 acres of land. BSEP would be located adjacent to California State Route 14 just north of the community of California City, in an unincorporated area of eastern Kern County, California on the western edge of the Mojave Desert. Three groups of parcels were purchased for the project site. Four individual Phase I Environmental Site Assessments (ESA's) were completed for the project. The first group of parcels consists of 24 parcels covering 2,273 acres, which included the Fremont Valley Ranch complex (DB 2008d, Data Request 54), although the project will be developed on 2,012 acres of the ranch site. The Fremont Valley Ranch was developed in 1977 as an alfalfa farm. The agricultural activities ceased in the mid-1980's (BS 2008a, page 5.16-10). Two additional Phase I ESAs were completed for a 14-acre and 80-acre parcels of undeveloped land (DB 2008d, Data Responses 54 and 55). Refer to **WASTE MANAGEMENT Figure 2.**The majority of parcels consist of desert that has been disturbed by past agricultural practices associated with alfalfa farming. With the exception of the main Ranch complex, 12 widely scattered irrigation wells, and several barn structures the majority of the parcels are undeveloped land. A Phase I ESA was conducted along the route and it was determined that no recognized environmental conditions (REC), or historical RECs were identified along the pipeline route (DB 2008j, Data Request-56).

WASTE MANAGEMENT Figure 3 shows the location of recognized environmental conditions (REC's) that were identified during the Phase I ESA's. These REC's include underground storage tanks, buildings and irrigation wells in relation to the BSEP plant site boundary. Except for an open barn structure in the middle of the property and an irrigation water reservoir, all of the buildings and underground fuel storage tanks are located within the Fremont Valley Ranch complex, the group of buildings that is just south of the access road that goes onto the site from SR-14 (DB 2008j). None of the Fremont Valley Ranch complex will be within the fenced BSEP Plant Site. Note that all recognized environmental conditions are located outside the plant site boundary. Any environmental conditions that may result in an impact would not be mitigated as a part of this project.

Construction Impacts and Mitigation

Site preparation and construction of the proposed project and its associated facilities would last approximately 25 months (BS 2008a, page 1-3) and generate both non-hazardous and hazardous wastes in solid and liquid forms. Before construction can begin, the project owner will be required to develop and implement a Construction

Waste Management Plan as described in the proposed Condition of Certification **WASTE-1**. This plan must describe all waste streams and methods of managing each waste.

Non-Hazardous Wastes

Construction activities as described in the AFC would include site clearing and grading, installation of footings, and installation of the parabolic troughs (BS 2008a, Table 2.14-1). Construction non-hazardous solid waste, totaling about 40 cubic yards per week, would consist of paper, wood, glass, plastics from packing material, waste lumber, insulation, scrap metal and concrete, and empty non-hazardous chemical containers (BS 2008a,, Table 5.16-5). All non-hazardous wastes would be recycled to the greatest extent possible and non-recyclable wastes would be collected by a licensed hauler and disposed of in a solid waste disposal facility (Class III landfill), per Title 14, California Code of Regulations, Section 17200 et seq. (*Minimum Standards for Solid Waste Handling and Disposal*), or in clean fill sites (BS 2008a, page 5.16-12). Staff proposes Condition of Certification **WASTE-2** which will require the applicant to identify facilities receiving waste and maintain documentation showing the type and volume of waste disposed. This information shall be maintained at the project site and made accessible to regulatory agencies.

Non-hazardous liquid wastes would be generated during construction, and would include sanitary waste (BS 2008a, page 5.16-11). Please see the **Soil and Water Resources** section of this document for more information on the management of project wastewater.

Hazardous Wastes

During construction, anticipated hazardous wastes include waste paint, spent construction solvents, waste cleaners, waste oil, oily rags, waste batteries, and spent welding materials. Approximately 175 gallons of solvents, used oil, paint and oily rags, and 1,000 gallons of Chelant (a heat exchanger cleaning waste), plus 30 batteries, would be generated from construction of the project (BS 2008a, page 5.16-11). Empty hazardous material containers would be returned to the vendor or disposed at a hazardous waste facility; solvents, used oils, paint, oily rags, and adhesives would be recycled or disposed at a hazardous waste facility; and spent batteries would be disposed at a recycling facility (BS 2008a, Table 5.16-5 page 5.16-11).

Conditions of Certification **WASTE-3** and **WASTE-4** would require that the appropriate professionals oversee activities that may disturb hazardous materials or contaminated soil, determine if further sampling and analysis is required, and comply with agency requirements.

The construction contractor is considered to be the generator of hazardous wastes at this site during construction. Hazardous waste would be collected in hazardous waste accumulation containers and stored in a lay down area, warehouse/shop area, or storage tank on equipment skids for less than 90 days. The accumulated wastes would then be properly manifested, transported, and disposed of at a permitted hazardous waste management facility by licensed hazardous waste collection and disposal companies. Staff reviewed the disposal methods and concluded that all wastes would be disposed of in accordance with all applicable LORS. Should any construction waste management-related enforcement action be taken or initiated by a regulatory agency, the project owner would be required by the proposed Condition of Certification **WASTE-5** to notify the Compliance Project Manager (CPM) whenever the owner becomes aware of this action.

Operation Impacts and Mitigation

The proposed BSEP would generate both non-hazardous and hazardous wastes in solid and liquid forms under normal operating conditions. Before operations can begin, the project owner would be required to develop and implement an Operations Waste Management Plan as required in the proposed Condition of Certification **WASTE-6**.

Non-hazardous Solid Wastes

Non-hazardous solid wastes generated during project operations would consist of HTF waste from spills, spent dematerialized resin, cooling tower basin sludge, and spent softener resin. To ensure proper disposal of the 10 tons per year of the cooling tower basin sludge, staff proposed **WASTE-7** which requires that the project owner perform the appropriate tests to classify the waste and determine the appropriate method of disposal. Wastes would be recycled to the greatest extent possible and non-recyclable wastes would be removed on a regular basis for disposal in a Class III landfill (BS 2008a, pages 5.16-8 to 5.16-9). The project would generate approximately 800 cubic yards of non-hazardous solid waste per year (BS 2008a, page 5.16-13).

Non-hazardous Liquid Wastes

Non-hazardous liquid wastes generated during the project’s operation are further discussed in the **Soil and Water Resources** section of this document. Non-hazardous cooling tower blowdown and the sanitary wastewater would be disposed of in evaporation ponds and a septic leach field, respectively. Stormwater drainage would be drained away from the site to collection ponds and swales, from which the water would percolate or evaporate. Stormwater that comes in contact with hazardous wastes would also be considered hazardous liquid waste. These hazardous liquid wastes are discussed below.

Hazardous Wastes

The project owner/operator would be considered the generator of hazardous wastes at the site during facility operations. Therefore, the project owner’s unique hazardous waste generator identification number, obtained prior to construction in accordance with proposed Condition of Certification **WASTE-8**, would be retained and used for hazardous waste generated during facility operation.

The generation of hazardous wastes expected during routine project operation includes used hydraulic fluids, oils, greases, oily filters and rags, spent selective catalytic reduction catalysts, cleaning solutions and solvents, and batteries. In addition, spills and unauthorized releases of hazardous materials or hazardous wastes may generate contaminated soils or materials that may require corrective action and management as hazardous waste. Proper hazardous material handling and good housekeeping practices will help keep spill wastes to a minimum. However, to ensure proper cleanup and management of any contaminated soils or waste materials generated from hazardous materials spills, staff proposes Condition of Certification **WASTE-9** requiring the project owner/operator to report, clean up, and remediate as necessary, any hazardous materials spills or releases in accordance with all applicable federal, state, and local requirements. More information on hazardous material management, spill reporting, containment, and spill control and countermeasures plan provisions for the project are provided in the **Hazardous Material Management** section of the PSA.

The hazardous wastes generated during the operation of BSEP would be minor, with source reduction and recycling of wastes implemented whenever possible. The hazardous wastes would be temporarily stored on site, transported off site by licensed hazardous waste haulers, and recycled or disposed at authorized disposal facilities in accordance with established standards applicable to generators of hazardous waste (Title 22, CCR, §§ 66262.10 et seq.). Should any operations waste management-related enforcement action be taken or initiated by a regulatory agency, the project owner would be required by proposed Condition of Certification **WASTE-5** to notify the CPM whenever the owner becomes aware of any such action.

Impact on Existing Waste Disposal Facilities

Non-hazardous Solid Wastes

Non-hazardous waste disposal sites suitable for discarding project-related construction and operation wastes are identified in Section 5.16.2.1 of the AFC (BS 2008a). Non-hazardous solid waste would be disposed at the six permitted Class III landfills located in Kern County. As shown on Table 5.16-4 of the AFC, all six landfills have significant remaining capacity to operate through their estimated closure dates which vary from 2014 through 2038 (BS 2008a, page 5.16-8).

The total amount of non-hazardous waste generated from project construction and operation is expected to contribute less than 1 percent of available landfill capacity. Disposal of the solid wastes generated by the BSEP would not significantly impact the capacity or remaining life of any of these facilities.

Hazardous Wastes

Section 5.16.2.2 of the AFC discusses two of California's Class I landfills: Clean Harbor's Buttonwillow landfill in Kern County and Waste Management's Kettleman Hills landfill in Kings County (BS 2008a, page 5.16-9). The Kettleman Hills facility accepts Class I waste. In total, there is a combined excess of 16 million cubic yards of remaining hazardous waste disposal capacity at these landfills, with at least 30 years remaining in their operating lifetimes. In addition, the Kettleman Hills facility is in the process of permitting an additional 15 million cubic yards of disposal capacity, and the Buttonwillow facility has 40 years to reach its capacity at its current disposal rate (BS 2008a, page 5.16-9).

All hazardous wastes generated during both construction and operation would be transported off site to a permitted treatment, storage, or disposal facility for appropriate disposition, preferably through recycling. The volume of hazardous waste from the BSEP requiring off-site disposal would be far less than staff's threshold of significance, which is 10 percent of the existing combined capacity of the two Class I landfills, and would therefore not significantly impact either the capacity or remaining life of these facilities.

CUMULATIVE IMPACTS

No cumulative impacts have been identified in the project vicinity that would create significant waste management impacts. Due to the insignificant impacts on individual disposal facilities described above, and the availability of additional regional landfills, staff believes cumulative impacts would likely be insignificant for both hazardous and nonhazardous waste disposal.

COMPLIANCE WITH LORS

Energy Commission staff concludes that the BSEP would comply with all applicable LORS regulating the management of hazardous and non-hazardous wastes during both facility construction and operation. The project owner is required to recycle and/or dispose hazardous and non-hazardous waste at facilities licensed or otherwise approved to accept the wastes. Because hazardous wastes would be produced during project operation, the BSEP would be required to obtain a hazardous waste generator identification number from U.S. EPA. The BSEP would also be required to properly store, package, and label waste; use only approved transporters; prepare hazardous waste manifests; keep detailed records; and appropriately train employees, in accordance with state and federal hazardous waste management requirements.

Staff has determined that management of the waste generated during construction and operation would comply with waste management laws, ordinances, regulations, and standards.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

Staff received a letter from the Department of Toxic Substances Control (DTSC). The comments in the letter stated that “DTSC has no concerns regarding the future management of hazardous waste at the proposed Beacon Solar Energy Project” (DTSC 2008A).

Bill O’Rullian, Supervisor Solid Waste Program, Kern County Environmental Health Services Department requested a requirement of the project owner to assure "cradle to grave" accountability for waste streams generated at the facility, and prevent illegal dumping, off-site stockpiles, or conditions that constitute a zoning violation or public health nuisance in the counties of Kern, Los Angeles, and San Bernardino. Staff has added Condition of Certification **WASTE-2** to address this concern.

CONCLUSIONS

Consistent with the three main objectives for staff's waste management analysis (as noted in the Introduction section of this analysis), staff provides the following conclusions:

1. After review of the applicant's proposed waste management procedures, staff concludes that project wastes would be managed in compliance with all applicable waste management LORS. Staff notes that both construction and operation wastes would be characterized and managed as either hazardous or non-hazardous waste. All non-hazardous wastes would be recycled to the extent feasible, and non-recyclable wastes would be collected by a licensed hauler and disposed of at a permitted solid waste disposal facility. Hazardous wastes would be accumulated onsite in accordance with accumulation time limits (90,180, 270, or 365 days depending on waste type and volumes generated), and then properly manifested, transported to, and disposed of at a permitted hazardous waste management facility by licensed hazardous waste collection and disposal companies.

   However, to help ensure and facilitate ongoing project compliance with LORS, staff proposes Conditions of Certification **WASTE-1** through **9**. These conditions would require the project owner to do all of the following:

   - Ensure the project site is investigated and any contamination identified is remediated as necessary, with appropriate professional and regulatory agency oversight (**WASTE-1**, **3**, **4**, **5**, and **6**).
   - Obtain a hazardous waste generator identification number (**WASTE-8**).
   - Prepare Construction Waste Management and Operation Waste Management Plans detailing the types and volumes of wastes to be generated and how wastes will be managed, recycled, and/or disposed of after generation (**WASTE-1** and **6**).
   - Ensure that all spills or releases of hazardous substances are reported and cleaned-up in accordance with all applicable federal, state, and local requirements (**WASTE-9)**.
   - Report any waste management-related LORS enforcement actions and how violations will be corrected (**WASTE-5**).

2. Existing conditions at the BSEP project site do include areas where prior site uses may have resulted in releases of hazardous substances or soil contamination. To ensure that the project site is investigated and remediated as necessary and to reduce any impacts from prior or future hazardous substance or hazardous waste releases at the site to a level of insignificance, staff proposes Conditions of Certification **WASTE-1**, **2**, **3**, **5**, **6**, **8**, and **9**. These conditions would require the project owner to ensure that the project site is investigated and remediated as necessary; demonstrate that project wastes are managed properly; and ensure that any future spills or releases of hazardous substances or wastes are properly reported, cleaned-up, and remediated as necessary. Therefore, staff concludes that

construction and operation of the proposed BSEP project would not result in contamination or releases of hazardous substances that would pose a substantial risk to human health or the environment.

3. Regarding impacts of project wastes on existing waste disposal facilities, staff uses a waste volume threshold equal to ten (10) percent of a disposal facility's remaining capacity to determine if the impact from disposal of project wastes at a particular facility would be significant. The existing available capacity for the three Class III landfills that may be used to manage nonhazardous project wastes exceeds 87 million cubic yards. The total amount of nonhazardous wastes generated from construction and operation of BSEP would contribute less than 0.1 percent of the remaining landfill capacity. Therefore, disposal of project generated non-hazardous wastes would have a less than significant impact on Class III landfill capacity.

In addition, the two Class I disposal facilities that could be used for hazardous wastes generated by the construction and operation of BSEP have a combined remaining capacity in excess of 15 million cubic yards. The total amount of hazardous wastes generated by the BSEP project would contribute less than 0.02 percent of the remaining permitted capacity. Therefore, disposal of BSEP generated hazardous wastes would have a less than significant impact on the remaining capacity at Class I landfills.

Staff concludes that management of the waste generated during demolition, construction and operation of the BSEP project would not result in any significant adverse impacts, and would comply with applicable LORS, if the waste management practices and mitigation measures proposed in the BSEP project AFC and staff's proposed conditions of certification are implemented.

PROPOSED CONDITIONS OF CERTIFICATION

WASTE-1 The project owner shall prepare a Construction Waste Management Plan for all wastes generated during construction of the facility, and shall submit the plan to the CPM for review and approval. The plan shall contain, at a minimum, the following:

- a description of all construction waste streams, including projections of frequency, amounts generated and hazard classifications;
- a survey of structures to be demolished that identifies the types of waste to be managed; and
- management methods to be used for each waste stream, including temporary on-site storage, housekeeping and best management practices to be employed, treatment methods, and companies providing treatment services, waste testing methods to assure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/reduction plans.

Verification: No fewer than 30 days before the start of site mobilization, the project owner shall submit the Construction Waste Management Plan to the CPM for approval.

WASTE-2 During the construction phase, project owner shall require contracted waste and/or refuse haulers to document each waste load transferred from the construction site to a disposal site and/or recycling center. The contractor shall specifically identify permitted solid waste facilities or recycling centers and provide copies of weigh tickets to BSEP.

Verification: The project owner shall identify permitted solid waste facilities or recycling centers that receive plant waste and maintain copies of weigh tickets and manifests showing the type and volume of waste disposed. This information shall be maintained at the job site and made accessible to CPM and the Kern County Environmental Health Service Department Solid Waste Program.

WASTE-3 The project owner shall provide the resume of an experienced and qualified Professional Engineer or Professional Geologist, who shall be available for consultation during building removal, and soil excavation and grading activities, to the CPM for review and approval. The resume shall demonstrate experience in remedial investigation and feasibility studies.

The registered professional engineer or geologist shall be given full authority by the project owner to oversee any earth-moving activities that could disturb contaminated soil.

Verification: At least 30 days before the start of site mobilization, the project owner shall submit the resume to the CPM for review and approval.

WASTE-4 If potentially contaminated soil is unearthed during building removal or excavation at either the proposed site or at linear facilities, as evidenced by discoloration, odor, detection by handheld instruments, or other signs, the Professional Engineer or Professional Geologist shall inspect the site, determine the need for sampling to confirm the nature and extent of contamination, and file a written report to the project owner and to the CPM stating the recommended course of action.

Depending on the nature and extent of contamination, the Professional Engineer or Professional Geologist shall have the authority to temporarily suspend further activity at that location for the protection of workers or the public. If, in the opinion of the Professional Engineer or Professional Geologist, significant remediation may be required, the project owner shall contact the CPM and representatives of the Hazardous Materials Division of Kern County's Environmental Health Services Department for guidance and possible oversight.

Verification: The project owner shall submit any final reports filed by the Professional Engineer or Professional Geologist to the CPM within five days of their receipt. The project owner shall notify the CPM within 24 hours of any orders issued to halt construction.

WASTE-5 Upon learning of any impending waste management-related enforcement action by any local, state, or federal authority for violation of requirements imposed by federal law, the project owner shall notify the CPM of any action taken or proposed to be taken against the project itself, or against any waste hauler or disposal facility or treatment operator with which the owner contracts.

Verification: The project owner shall notify the CPM, in writing within 10 days of learning of an impending enforcement action. The CPM shall notify the project owner of any changes that will be required to the manner in which project-related wastes are managed.

WASTE-6 The project owner shall prepare an Operation Waste Management Plan for all wastes generated during operation of the facility (including construction, operation and dismantling of the onsite manufacturing building) and shall submit the plan to the CPM for review and approval. The plan shall contain, at a minimum, the following:

- a detailed description of all operation and maintenance waste streams, including projections of amounts to be generated, frequency of generation, and waste hazard classifications;
- management methods to be used for each waste stream, including temporary on-site storage, housekeeping and best management practices to be employed, treatment methods and companies providing treatment services, waste testing methods to ensure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/source reduction plans;
- information and summary records of conversations with the local Certified Unified Program Agency and the Department of Toxic Substances Control regarding any waste management requirements necessary for project activities. Copies of all required waste management permits, notices, and/or authorizations shall be included in the plan and updated as necessary;
- a detailed description of how facility wastes will be managed and any contingency plans to be employed, in the event of an unplanned closure or planned temporary facility closure; and
- a detailed description of how facility wastes will be managed and disposed upon closure of the facility.

Verification: The project owner shall submit the Operation Waste Management Plan to the CPM for approval no less than 30 days prior to the start of project operation. The project owner shall submit any required revisions to the CPM within 20 days of notification from the CPM that revisions are necessary. The project owner shall also document in each Annual Compliance Report the actual volume of wastes generated and the waste management methods used during the year; provide a comparison of the actual waste generation and management methods used to those proposed in the original Operation Waste Management Plan; and update the Operation Waste Management Plan as necessary to address current waste generation and management practices.

WASTE-7 The project owner shall ensure that the cooling tower basin sludge is tested pursuant to Title 22, California Code of Regulations, and section 66262.10 and report the findings to the CPM

Verification: The project owner shall report the results of filter cake testing to the CPM. If two consecutive tests show that the sludge is non-hazardous, the project owner may apply to the CPM to discontinue testing.

WASTE-8 The project owner shall obtain a hazardous waste generator identification number from the Department of Toxic Substances Control prior to generating any hazardous waste during operations.

Verification: The project owner shall keep its copy of the identification number on file at the project site and notify the CPM of its receipt in the relevant monthly compliance report.

WASTE-9 The project owner shall ensure that all spills or releases of hazardous substances, materials, or waste are reported, cleaned up, and remediated as necessary, in accordance with all applicable federal, state, and local requirements.

Verification: The project owner shall document all unauthorized releases and spills of hazardous substances, materials, or wastes that occur on the project property or related pipeline and transmission corridors. The documentation shall include, at a minimum, the following information: location of release; date and time of release; reason for release; volume released; amount of contaminated soil/material generated; how release was managed and material cleaned up; if the release was reported; to whom the release was reported; release corrective action and cleanup requirements placed by regulating agencies; level of cleanup achieved and actions taken to prevent a similar release or spill; and disposition of any hazardous wastes and/or contaminated soils and materials that may have been generated by the release. Copies of the unauthorized spill documentation shall be provided to the CPM within 30 days of the date the release was discovered.

REFERENCES

BS 2008a – FPL Energy/M. O'Sullivan (tn 45646). Application for Certification, dated 03/13/08. Submitted to CEC/Docket Unit on 03/14/08.

BS 2008c – Beacon Solar, LLC/G. Palo (tn 45972). AFC Volume 3 - Data Adequacy Supplement, dated 04/18/08. Submitted to CEC/Docket Unit on 04/21/08.

BS 2008e – Beacon Solar, LLC/G. Palo (tn 46480). Draft Report of Waste Discharge, dated 05/23/08. Submitted to CEC/Docket Unit on 05/28/08.

CEC 2008c – California Energy Commission/E. Allen (tn 45787). Notice of Receipt of an Application for Certification, dated 03/27/08. Submitted to CEC/Docket Unit on 03/27/08.

CEC 2008e – California Energy Commission/E. Allen (tn 45785). Request for Agency (State and Federal) Participation in the Review the Application for Certification, dated 03/27/08. Submitted to CEC/Docket Unit on 03/27/08.

CEC 2008f – California Energy Commission/E. Allen (tn 45784). Request for Agency (Local) Participation in the Review of the Application for Certification, dated 03/27/08. Submitted to CEC/Docket Unit on 03/27/08.

CEC 2008g – California Energy Commission/M. Jones (tn 45873). Data Adequacy Recommendation, dated 04/11/08. Submitted to CEC/Docket Unit on 04/11/08.

CEC 2008j – California Energy Commission/M. Jones (tn 46027). Data Adequacy Recommendation, dated 04/25/08. Submitted to CEC/Docket Unit on 04/28/08.

CEC 2008cc – California Energy Commission/B. Pfanner (tn 46719). Data Requests 1 through 70, dated 06/16/08. Submitted to CEC Docket Unit on 06/16/08.

CEC 2008oo – California Energy Commission/Beacon Solar (tn 47643). Supplemental Response to CEC Data Requests Set 1, dated 08/18/08. Submitted to CEC Docket Unit on 08/19/08.

CRWQ 2008a – CRWQCB / M. Hakakian (tn 46189). California Regional Water Quality Control Board's Comments on Beacon AFC, dated 04/30/08. Submitted to CEC/Docket Unit on 05/07/08.

DB 2008d – Downey Brand/L. Navarrot (tn 47078). Data Responses 1-70, dated 07/16/08. Submitted to CEC/Docket Unit on 07/16/08.

DB 2008j – Downey Brand/S. Rowland (tn 47103). Phase 1 Environmental Site Assessment. Submitted to CEC/Docket Unit on 07/17/08.

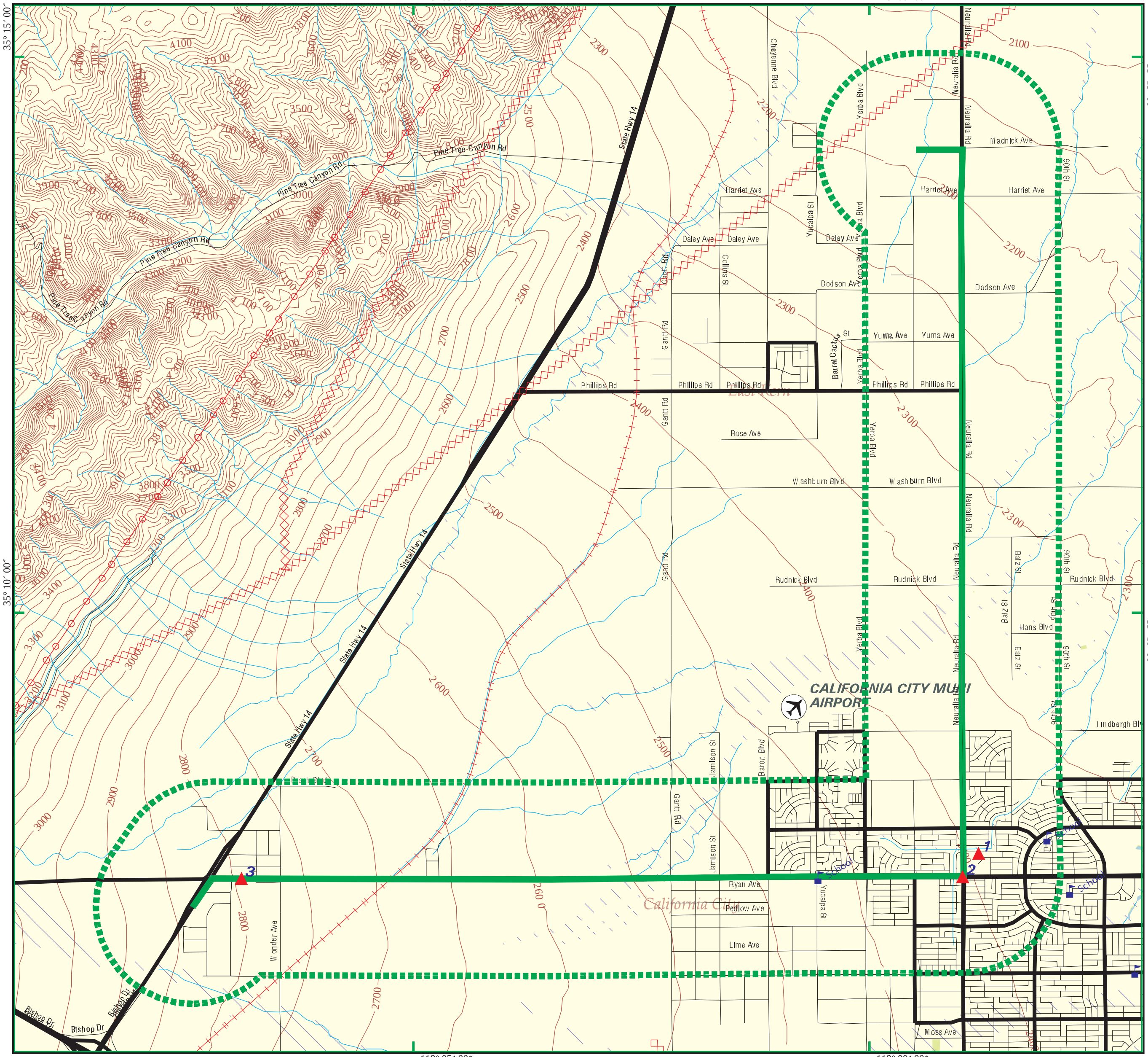
DB 2008n – DowneyBrand/ S. Rowlands (tn 48574). Supplemental Responses to CEC Data Request 14 & 17 through 127, dated 10/14/08. Submitted to CEC/Docket Unit on 10/14/08.

DTSC 2008a – Department of Toxic Substances Control/R. Hume (tn 46035). Letter in Response to Request for Agency Participation, dated 04/15/08. Submitted to CEC/Docket Unit on 04/28/08.

KCEHSD 2008 – W. O’Rullian Kern County Environmental health Services Department Solid Waste Program comments from William O’Rullian. Dated 11/26/2008. Submitted to CEC/Docket Unit on 11/26/2008.

WASTE MANAGEMENT - FIGURE 1

Beacon Solar Energy Project - 17.5 Mile Gas Pipeline Assessment



17.5 Mile Gas Pipeline Assessment

- Listed Sites
- Earthquake Epicenters (Richter 5 or greater)
- Search Boundary
- Roads
- Major Roads
- Waterways
- Railroads
- Contour Lines
- Pipelines
- Powerlines
- Fault Lines
- Water
- Superfund Sites
- Federal DOD Sites
- Indian Reservations BIA
- 100-Yr Flood Zones
- National Wetland Inventory

N

California City, CA

0 1/2 1

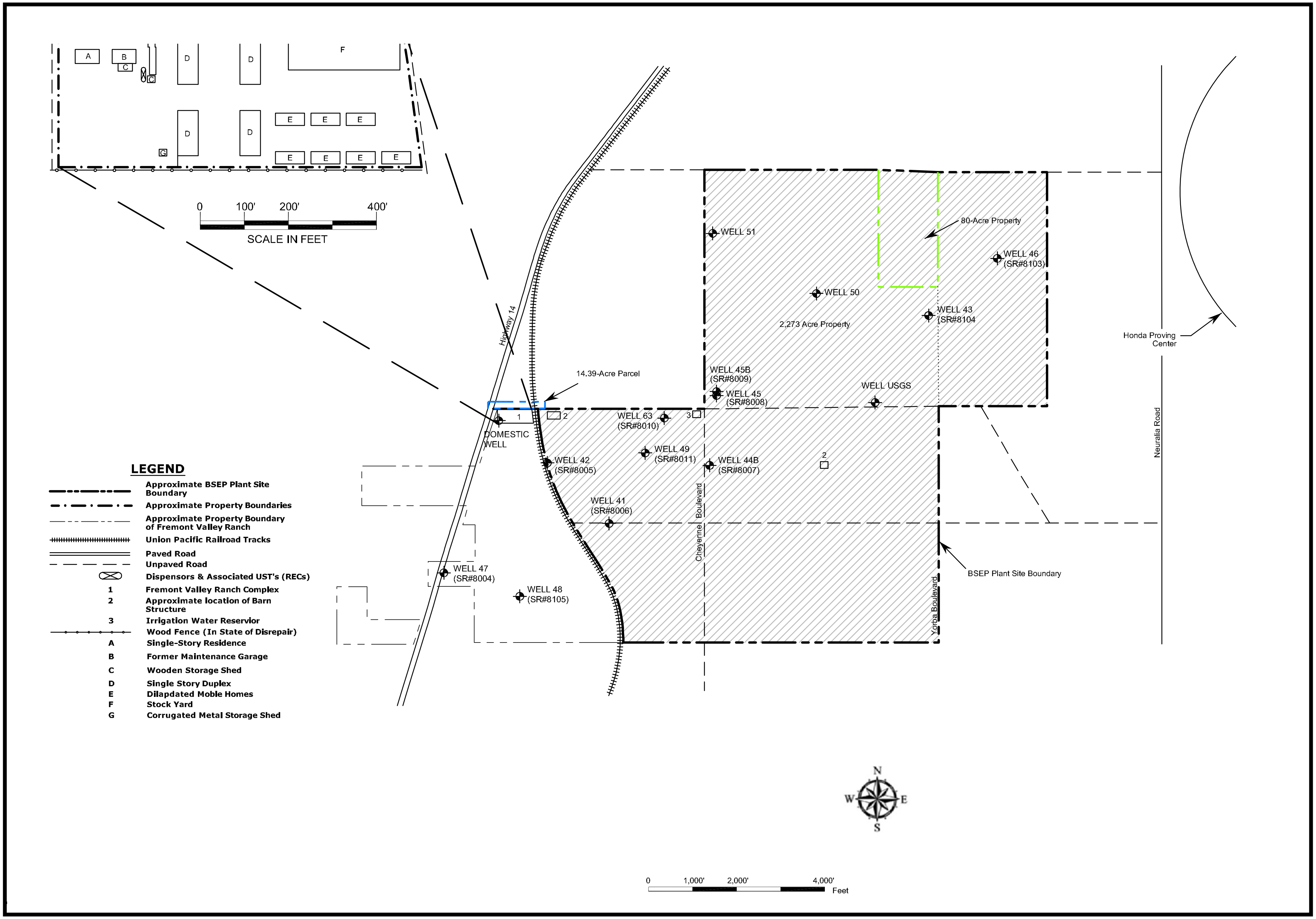
Scale in Miles

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: CEC Data Requestes 1-70, July 2008

WASTE MANAGEMENT - FIGURE 2

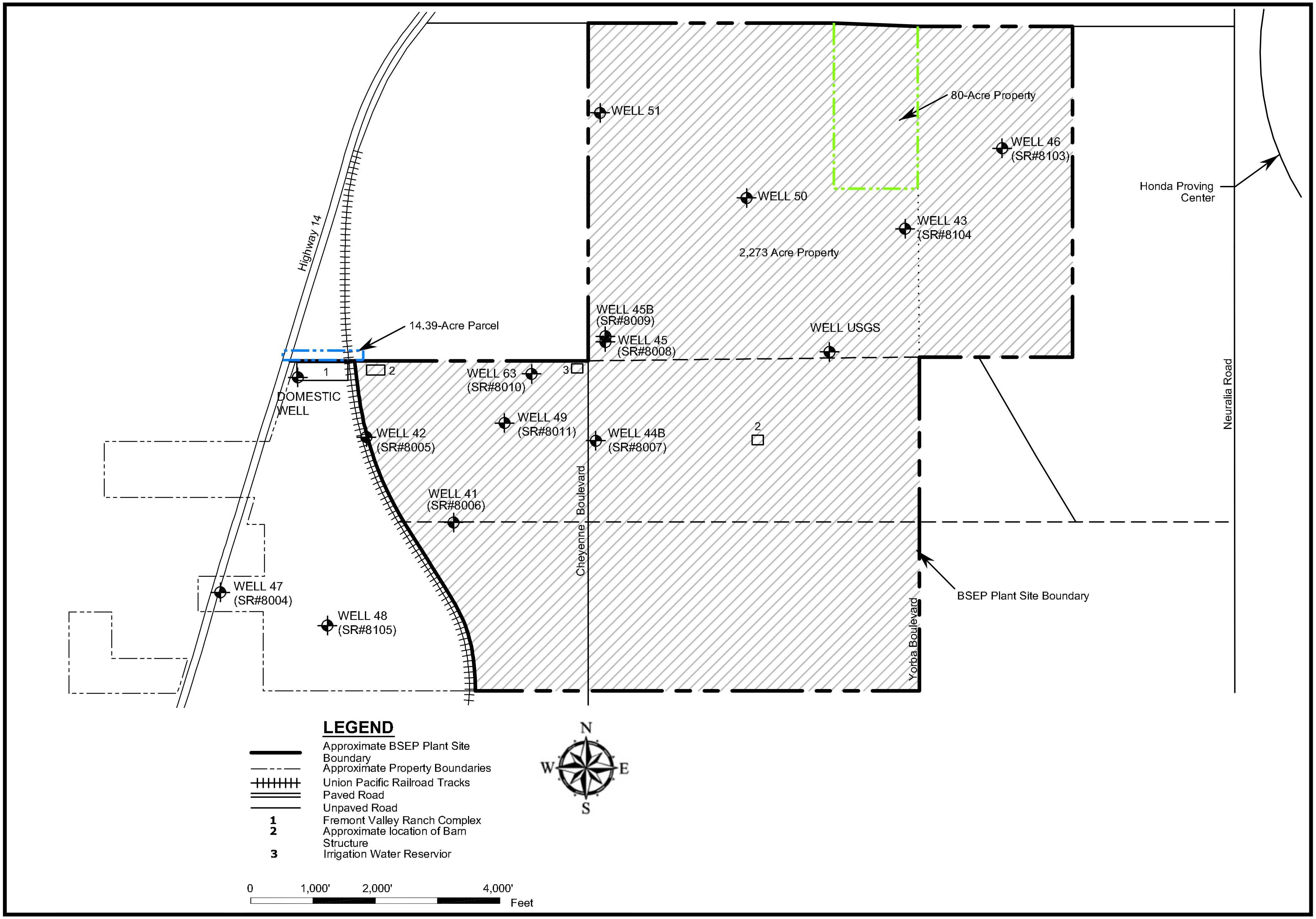
Beacon Solar Energy Project - Location of Recognized Environment Conditions



SOURCE: CEC Data Requestes 1-70, July 2008

WASTE MANAGEMENT - FIGURE 3

Beacon Solar Energy Project - Plant Site Boundary and Property Purchases



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: CEC Data Requestes 1-70, July 2008

WORKER SAFETY AND FIRE PROTECTION

Geoff Lesh, PE and Rick Tyler

SUMMARY OF CONCLUSIONS

Staff concludes that if the applicant for the proposed Beacon Solar Energy Project (BSEP) 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 (LORS). 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.

Staff also concludes that the proposed project would not have significant impacts on local fire protection services. The fire risks at the proposed facility do not pose significant added demands on local fire protection services. Staff also concludes that the Kern County Hazmat Team and the Kern County Fire Department (KCFD) are adequately equipped and staffed to respond to hazardous materials incidents at the proposed facility with an adequate response time (Eckroth 2008).

INTRODUCTION

Worker safety and fire protection are regulated through federal, state, and local 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 BSEP 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 CCR Part 9)	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 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.

SETTING

Fire support services to the site will be under the jurisdiction of the Kern County Fire Department (KCFD). Station 14 is 19 miles from the project site, located at 1953 Highway 58, Mojave, California, and would be the first responder to BSEP with a response time of approximately 23 minutes. Kern County Fire Department also has mutual aid agreements with California City Fire Department and Edwards Air Force Base for responses requiring more assistance.

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.

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 BSEP 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 if the presence of the power plant would cause a significant impact on a local fire department. If it does, staff will recommend that the applicant 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 BSEP 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

BSEP includes the construction and operation of a hybrid power plant, that includes natural gas boilers and solar thermal generating equipment. For the Power Block, workers will be exposed to hazards typical of construction and operation of a gas-fired simple-cycle facility, while the solar component will present similar construction risks and minimal operational risks to workers.

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 AFC includes adequate outlines for each of the above programs (BS 2008a, section 5.18.3.1). 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 BSEP, 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 BSEP, 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 (BS 2008a, section 5.18.3.1). Prior to operation of BSEP, 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 (BS 2008a, section 5.18.3.1):

- 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 construction 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 (BS 2008a, section 5.18.3.1). 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 fire fighting 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 BSEP operational environment will require PPE.

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 (BS 2008a, section 5.18.3.1).

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 Safety Issues

This solar power plant will present a unique work environment that includes a solar field located in the high desert. The area under the solar arrays must be kept free from weeds and thus herbicides will be applied as necessary. Exposure to workers via inhalation and ingestion of dusts containing herbicides poses a health risk. Finally, workers will regularly inspect the solar array for broken or non-functioning mirrors by driving up and down dirt paths between the rows of mirrors and even under the mirrors. Cleaning and servicing the mirrors will also be conducted on a routine schedule. All these activities will take place year-round and especially during the summer months of peak solar power generation, when outside ambient temperatures routinely reach 115 °F and above.

The applicant has indicated that workers will be adequately trained and protected, but has not included precautions against exposure to herbicides. Therefore, to ensure that workers are indeed protected, staff has proposed additional requirements found in Conditions of Certification **WORKER SAFETY-6**. This requirement consists of the following provisions:

- The development and implementation of Best Management Practices (BMP) for the storage and application of herbicides used to control weeds beneath and around the solar array.

A BMP requiring proper herbicide storage and application, as recommended in Condition of Certification **WORKER SAFETY-6,** will mitigate potential risks to workers from exposure to herbicides and reduce the chance that herbicides will contaminate either surface water or groundwater. Staff suggests that a BMP follow either the guidelines established by the U.S. EPA (EPA 1993), or more recent guidelines established by the State of California or U.S. EPA.

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 gas-fired 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 gas-fired 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 hotwork;
- 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.

Fire Hazards

During construction and operation of the proposed BSEP there is the potential for both small fires and major structural fires. Electrical sparks, combustion of fuel oil, natural gas, 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 spoke to a representative of 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. The 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. California City Fire Department and Edwards Air Force Base Fire Department would be called upon if needed, and as available, through a Mutual Aid Agreement with KCFD (Eckroth 2008).

Construction

During construction, portable fire extinguishers will be located and maintained throughout the site; safety procedures and training will also be implemented (BS 2008a, section 5.18.3.1). Station #14 of the KCFD in Mojave, California, will provide fire protection backup for larger fires that cannot be extinguished using the project's portable suppression equipment .

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, NFPA and 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 personal to access the site should the main gate be blocked. The proposed BSEP has only one access point, that being from SR-14 and through the main gate. The AFC makes no mention of a secondary access to the site, or through the perimeter fence. Kern County Fire Department Fire Marshall David Goodell agrees with staff that a second access point is necessary to ensure fire department access and that a second access road is desirable. The preferred second access would be via Neuralia Road from the east side of the proposed facility, thereby providing an alternate route to the facility that does not require crossing the railroad tracks, nor using the primary entrance off of SR-14 on the west side of the facility (Goodell 2009a, Goodell 2009b). 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. Therefore, in order to comply with the requirements of LORS, staff proposes a Condition of Certification **WORKER SAFETY-7** that would require the project owner to identify and provide a second access point to the site from Neuralia Road 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, power plants 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 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 trained in its use.

CUMULATIVE IMPACTS AND MITIGATION

Staff reviewed the construction and operation of BSEP could have on the fire and emergency service capabilities of the KCFD. Staff agrees with the applicant that combined impacts would not be significant and that existing local services would adequately provide emergency services.

CONCLUSIONS

Staff concludes that if the applicant for the proposed BSEP 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**-7**, BSEP 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:

- An Operation Injury and Illness Prevention Plan;
- An Emergency Action Plan;
- Hazardous Materials Management Program;
- Fire 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.

<u>Verification:</u> 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.

<u>Verification:</u> 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 prepare and implement a Best Management Practices (BMPs) for the storage and application of herbicides used to control weeds beneath and around the solar array. These plans shall be submitted to the CPM for review and approval.

<u>Verification:</u> At least thirty (30) days prior to the start of site mobilization, the project owner shall submit to the CPM for review and approval a copy of the Best Management Practices (BMPs) for the storage and application of herbicides.

WORKER SAFETY-7 The project owner shall identify and provide a second access point for emergency personnel to enter the site. This access would enter from Neuralia Road, unless the Kern County Fire Department agrees to an alternative route. This access 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.

<u>Verification:</u> At least 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 for 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.

REFERENCES

BS 2008a - FPL Energy/M. O'Sullivan (tn 45646). Application for Certification, dated 03/13/08. Submitted to CEC/Docket Unit on 03/14/08.

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ENGINEERING ASSESSMENT

FACILITY DESIGN

Erin Bright and Steve Baker

SUMMARY OF CONCLUSIONS

The California Energy Commission staff concludes that the design, construction, and eventual closure of the Beacon Solar Energy 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 Beacon Solar Energy 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

Lists of LORS applicable to each engineering discipline (civil, structural, mechanical, and electrical) are described in the AFC (BS 2008a, AFC § 5.7.1.3, Table 5.7-1). 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 California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations)
Local	Kern County General Plan Kern County Zoning Ordinance
General	American National Standards Institute (ANSI) American Society of Mechanical Engineers (ASME) American Welding Society (AWS) American Society for Testing and Materials (ASTM)

SETTING

The Beacon Solar Energy Project (Beacon), a 250 MW solar thermal power plant facility utilizing a parabolic trough design with oil based heat transfer fluid, would be built on a 2,012-acre section in eastern Kern County. The site lies in Seismic Risk Zone 4. For more information on the site and related project description, please see the **Project Description** section of this document. Additional engineering design details are contained in the AFC (Appendices C and D).

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 life 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 scheme 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 Beacon AFC, Appendices C and D, for representative lists 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; used for the storage, containment, or handling of hazardous or toxic materials; or capable of becoming potential health and safety hazards if not constructed according to applicable engineering LORS. Major structures and equipment are identified in the proposed Condition of Certification **GEN-2,** below.

Beacon shall 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 project's AFC (BS 2008a, AFC § 3.7.4, Appendix 2C) describes a quality control 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. Compliance with design requirements will be verified through specific inspections, audits, and testing. Implementation of this quality assurance/quality control (QA/QC) program will ensure that Beacon is actually designed, procured, fabricated, and installed as described in this analysis.

COMPLIANCE MONITORING

Under Section 104.1 in Appendix Chapter 1 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 103.3 in Appendix Chapter 1 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 typically 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, section 108 in Appendix Chapter 1, 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, consistent with CBC section 108, 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 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) that 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 and 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 Beacon 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** section 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 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 laws, ordinances, regulations and standards (LORS) in effect at the time initial design plans are submitted to the chief building official (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 (2007 CBC, Appendix Chapter 1, § 101.2, Scope). 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 compliance project manager (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 (2007 CBC, Appendix Chapter 1, § 110, Certificate of Occupancy).

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, master drawing, and master specifications lists. The schedule shall contain a list of proposed submittal packages of designs, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide specific packages to the CPM upon request.

<u>Verification:</u> At least 60 days (or within 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, the master drawing, and master specifications lists of documents to be submitted to the CBO for review and approval. These documents shall be the pertinent design documents for the major structures and equipment listed in **Facility Design Table 2,** below. Major structures and equipment shall be added to or deleted from the table only with CPM approval. The project owner shall provide schedule updates in the monthly compliance report.

Facility Design Table 2
Major Structures and Equipment List

Equipment/System	Quantity (Plant)
Steam Turbine Generator Foundation and Connections	1
Start-up Boilers Foundations and Connections	2
GSU Transformer Foundation and Connections	1
Unit Auxiliary Transformers Foundations and Connections	2
SUS Transformers Foundations and Connections	4
Gas Storage Area Foundation and Connections	1
Cooling Tower Foundation and Connections	1
Raw & Fire Water Storage Tank Foundation and Connections	1
Firewater Pump House Foundation and Connections	1
Process Water Storage Tank Foundation and Connections	1
Process Water Pump Skid Foundation and Connections	4
Demineralized Water Storage Tank Foundation and Connections	1
Demineralized Water Pump Skid Foundation and Connections	1
Demineralized Water Treatment Facility Foundation and Connections	1
Water Treatment Building Foundation and Connections	1
Control and Administration Building Foundation and Connections	1
Feed Water Pumps Foundations and Connections	3
Condensate Pumps Foundations and Connections	3
Economizers Foundations and Connections	4
Reheaters Foundations and Connections	9
Evaporators Foundations and Connections	9
Superheaters Foundations and Connections	5
Expansion Storage Tanks Foundations and Connections	6
HTF Freeze Protection Heat Exchangers Foundations and Connections	2
HTF Circulation Pumps Foundations and Connections	6
Steam Blowdown Tank Foundation and Connections	1
Circulating Water Pumps Foundation and Connections	1
Neutralization Storage Tank Foundation and Connections	1
Solar Field Reflectors and Receivers Foundations and Connections	1 Lot

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 (2007 CBC, Appendix Chapter 1, § 108, Fees; Chapter 1, Section 108.4, Permits, Fees, Applications and Inspections), 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, structural engineer, or civil engineer, as the resident engineer in charge of the project (2007 California Administrative Code, § 4-209, Designation of Responsibilities). 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 resident engineer 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 resident engineer 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 shall have the authority to halt construction and to require changes or remedial work if the work does not meet requirements.

If the resident engineer 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.

<u>Verification:</u> At least 30 days (or within a 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 resident engineer and any other delegated engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the resident engineer and other delegated engineer(s) within five days of the approval.

If the resident engineer 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 (2007 CBC, Appendix Chapter 1, § 104, Duties and Powers of Building Official).

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; and 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 resident engineer 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 (2007 CBC, Appendix J, § J104.3, Soils Report; Chapter 18, § 1802.2, Foundation and Soils Investigations);

   3. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with requirements set forth in the 2007 CBC, Appendix J, section J105, Inspections, and the 2007 California Administrative Code, section 4-211, Observation and Inspection of Construction (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 resident engineer.

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 (2007 CBC, Appendix Chapter 1, § 114, Stop Orders).

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 California Administrative Code, section 4-211, Observation and Inspection of Construction (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 resident engineer 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 within a 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 within a 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, 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, Chapter 17, Section 1704, Special Inspections; Chapter 17A, Section 1704A, Special Inspections; and Appendix Chapter 1, Section 109, Inspections. 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. Observe the work assigned for conformance with the approved design drawings and specifications;

3. Furnish inspection reports to the CBO and resident engineer. All discrepancies shall be brought to the immediate attention of the resident engineer for correction, then, if uncorrected, to the CBO and the CPM for corrective action (2007 CBC, Chapter 17, § 1704.1.2, Report Requirements); and

4. Submit a final signed report to the resident engineer, 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 within a 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 (2007 CBC, Appendix Chapter 1, § 109.6, Approval Required; Chapter 17, § 1704.1.2, Report Requirements). 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.

Verification: 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 an alternative site approved by the CPM during the operating life of the project (2007 CBC, Appendix Chapter 1, § 106.3.1, Approval of Construction Documents). 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" files (Adobe .pdf 6.0), 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 investigation reports required by the 2007 CBC, Appendix J, section J104.3, Soils Report, and Chapter 18, section 1802.2, Foundation and Soils Investigation.

Verification: At least 15 days (or within a 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 (2007 CBC, Appendix Chapter 1, § 114, Stop Work Orders).

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, Appendix Chapter 1, section 109, Inspections, and Chapter 17, section 1704, Special Inspections. 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 (2007 CBC, Chapter 17, § 1704.1.2, Report Requirements). 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 (2007 CBC, Chapter 17, § 1703.2, Written Approval).

Verification: Within 30 days (or within a 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 of any major structure or component listed in **FACILITY DESIGN Table 2** of Condition of Certification **GEN 2**, above, the project owner shall submit to the CBO for design review and approval the proposed lateral force procedures for project structures and the applicable designs, plans, and drawings for project structures. Proposed lateral force procedures, designs, plans, and drawings shall be those for the following items (from **Table 2**, above):

1. Major project structures;
2. Major foundations, equipment supports, and anchorage; and
3. Large field-fabricated tanks.

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 (2007 CBC, Appendix Chapter 1, § 109.6, Approval Required);
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 (2007 California Administrative Code, § 4-210, Plans, Specifications, Computations and Other Data);

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 (2007 CBC, Appendix Chapter 1, § 106.3.4, Design Professional in Responsible Charge); and

5. Submit to the CBO the responsible design engineer's signed statement that the final design plans conform to applicable LORS (2007 CBC, Appendix Chapter 1, § 106.3.4, Design Professional in Responsible Charge).

Verification: At least 60 days (or within a project owner- and CBO-approved alternative time frame) prior to the start of any increment of construction of any structure or component listed in **FACILITY DESIGN Table 2** of Condition of Certification **GEN-2**, above, 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 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, Chapter 17, section 1704, Special Inspections, and section 1709.1, Structural Observations.

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 (2007 CBC, Chapter 17, § 1704.1.2, Report Requirements). 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 necessary to obtain the 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 (2007 CBC, Appendix Chapter 1, § 106.1, Submittal Documents; § 106.4, Amended Construction Documents; 2007 California Administrative Code, § 4-215, Changes in Approved Drawings and Specifications).

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, Chapter 3, Table 307.1(2), shall, at a minimum, be designed to comply with the requirements of that chapter.

Verification: At least 30 days (or within a 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 **FACILITY DESIGN Table 2**, Condition of Certification **GEN-2**, above. 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 (2007 CBC, Appendix Chapter 1, § 106.1, Submittal Documents; § 109.5, Inspection Requests; § 109.6, Approval Required; 2007 California Plumbing Code, § 301.1.1, Approvals).

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 (2007 CBC, Appendix Chapter 1, § 106.3.4, Design Professional in Responsible Charge), 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
- San Luis Obispo County codes.

The CBO may deputize inspectors to carry out the functions of the code enforcement agency (2007 CBC, Appendix Chapter 1, § 103.3, Deputies).

Verification: At least 30 days (or within a project owner- and CBO-approved alternative time frame) prior to the start of any increment of major piping or plumbing construction listed in **FACILITY DESIGN Table 2**, Condition of Certification **GEN-2,** above, 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 (2007 CBC, Appendix Chapter 1, § 109.5, Inspection Requests).

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 within a 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 (2007 CBC, Appendix Chapter 1, § 109.3.7, Energy Efficiency Inspections; § 106.3.4, Design Professionals in Responsible Charge).

Verification: At least 30 days (or within a 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 (2007 CBC, Appendix Chapter 1, § 106.1, Submittal Documents). 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 (2007 CBC, Appendix Chapter 1, § 109.6, Approval Required; § 109.5, Inspection Requests). 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 diagrams 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.

Verification: At least 30 days (or within a 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

BS 2008a - FPL Energy/M. O'Sullivan (tn 45646). Application for Certification, dated 03/13/08. Submitted to CEC/Docket Unit on 03/14/08.

GEOLOGY AND PALEONTOLOGY

Dal Hunter, Ph.D., C.E.G.

SUMMARY OF CONCLUSIONS

The proposed Beacon Solar Energy Project (BSEP) is located in a geologically active area of the northwestern Mojave Desert Geomorphic Province, east-central Kern County in Southeastern California. Because of its geologic setting, the site could be subject to intense levels of earthquake-related ground shaking. Due to its close proximity to the western and central traces of the Garlock Fault there is some potential for ground rupture in the site vicinity. The effects of strong ground shaking would need to 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. Subsidence due to historical ground water pumping in the Fremont Valley and/or dilation due to pull-apart faulting between the western and central strands of the Garlock Fault have resulted in formation of localized tension cracks and surface fissuring along stress planes parallel to the Garlock Fault system. A geotechnical investigation has been performed and presents standard engineering design recommendations for mitigation of seismic shaking and site soil conditions. Further investigation in the area of the proposed power block is needed to verify the absence of faults, tension cracking, and subsurface fissuring. Likewise, a geologist experienced in recognition and examination of faults and fissures should be available during trenching performed for construction of the ancillary facilities, particularly the natural gas pipeline, to document any potential near surface soil anomalies and facilitate any appropriate changes in design. The additional fault/fissure evaluation is detailed in proposed Condition of Certification **GEO-1**.

There are no known viable geologic or mineralogical resources at the proposed BSEP site. Regionally, paleontological resources have been documented within Quaternary older alluvium, similar to deposits that underlie the site, but no significant fossils were found during field explorations at the plant site. Potential impacts would also be mitigated through worker training and monitoring by qualified paleontologists, as required by proposed Conditions of Certification **PAL-1** through **PAL-7**.

Based on its independent research and review, the California Energy Commission believes that the potential is low for significant adverse impacts to the proposed project from geologic hazards during its design life and to potential geologic, mineralogic, and paleontological resources from the construction, operation, and closure of the proposed project. It is staff’s opinion that the BSEP could be designed and constructed in accordance with all applicable laws, ordinances, regulations, and standards and in a manner that would both protect environmental quality and assure public safety, to the extent practical.

INTRODUCTION

In this section, California Energy Commission (Energy Commission) staff discusses the potential impacts of geologic hazards on the proposed BSEP site as well as the potential to affect geologic, mineralogic, and paleontological resources. Staff's objective is to ensure that there would be no consequential adverse impacts to significant geological and paleontological resources during the 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) (BS 2008a). The following briefly describes the current LORS for both geologic hazards and resources and mineralogic and paleontological resources.

Geology and Paleontology Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	The proposed BSEP 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. Portions of the site and proposed ancillary facilities are located within designated Alquist-Priolo Fault Zones. The proposed site layout places occupied structures outside of the 50-foot setback zone.
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 paleontological resources, the Energy Commission relies on guidelines from the Society for Vertebrate Paleontology, indicated below.

Applicable Law	Description
California Environmental Quality Act (CEQA), PRC sections 15000 et seq., Appendix G	Mandates that public and private entities identify the potential impacts on the environment during proposed activities. Appendix G outlines the requirements for compliance with CEQA and provides a definition of significant impacts on a fossil site.
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.
Local	
Kern County Grading Code, (Ord. 17.28.040, 2008)	Kern County grading permit is required for earth moving activities in excess of 50 cubic yards.
Kern County Floodplain Management Ordinance, (Ord. 17.48.140, 2008)	A Kern County development permit is required prior to construction or development within an area of special flood hazards, areas of flood related erosion hazards, or areas of potential mudslides.

SETTING

The proposed BSEP would be constructed on 2,012 acres of privately-owned vacant land within a 2,317-acre parcel east of State Route 14 approximately 4 miles north-northwest of California City in Kern County, California. With the exception of active drainages, the site was cleared and graded during the mid-1900's for agriculture which continued until the mid-1980's. The site is partially fenced and hosts approximately 14 disused irrigation wells. A shallow ephemeral drainage crosses the site from southwest to northeast near its center and serves to convey infrequent runoff from catchment areas south and southwest of the site to the fluvially isolated playa of Koehn Lake approximately 5 miles to the east-northeast.

The proposed BSEP would be a primary power generating facility capable of producing 250 MW of electricity from a parabolic trough linear receiver solar array. The high flash point fluid, which would circulate within the closed-loop linear receiver array, would be used to generate steam which would drive the electricity generating turbine system. A natural gas fired boiler system would be used to maintain system circulation during the night and periods of heavy cloud cover, and would provide power during system startup each morning. Ancillary facilities associated with the solar array would include a 17.6-mile natural gas pipeline to supply the boiler generator, an above-ground electrical transmission connection to the existing Los Angeles Department of Water and Power electrical grid west of the site, connection to existing water supply well(s) on the property for process water, a cooling tower, an onsite septic system, a control building, paved and unpaved roads, and various smaller outbuildings to house maintenance and security personnel and equipment.

REGIONAL SETTING

The proposed BSEP would to be located in the Koehn Lake sub-basin of Fremont Valley, an enclosed drainage basin in the northwest corner of the Mojave Desert Geomorphic Province in eastern Kern County, California. The Mojave Desert is a broad interior region of isolated mountain ranges which separate vast expanses of desert plains and interior drainage basins and occupies approximately 25,000 square miles in southeastern California and portions of Nevada, Utah, and Arizona. In California, its overall topography is dominated by southeast to northwest trending faulting with a secondary east to west trending alignment which is correlateable to Transverse Range faulting. The proposed BSEP site is located near the northwest boundary of the Mojave Desert Geomorphic Province where it terminates against the Garlock Fault. North of Fremont Valley, the Garlock fault defines the northern boundary of the Mojave Desert province where it meets the southern end of the Basin and Range province. In Fremont Valley, the Garlock Fault defines the northwest border of the Mojave Desert province, separating it from the southern end of the Sierra Nevada Geomorphic Province. Further south a portion of the Garlock Fault and the San Andreas Fault define an abrupt topographic transition between the Mojave Desert province and the Transverse Range Geomorphic Province.

PROJECT SITE DESCRIPTION

The proposed BSEP site is located on vacant land east of California State Route 14 approximately four miles north-northwest of California City and 15 miles north of Mojave in eastern Kern County, California. The site is located in an enclosed drainage basin within Fremont Valley in the northwest portion of the Mojave Desert Geomorphic Province. Drainage within the enclosed basin occurs along ephemeral streams which flow toward the normally dry lakebed of Koehn Lake approximately 5 miles northeast of the site. The site is located on partially cleared and graded land formerly used for agricultural crops including alfalfa. The property is partially fenced and approximately 14 disused irrigation wells are present on the site. Access is obtained from a gravel road leading east from SR-14 past several abandoned farm structures and across the north to south trending Union Pacific Railroad tracks. The site is relatively flat with elevations ranging from approximately 2,220 feet in the south to 2,025 feet at the northern boundary. A prominent change in topography, formed by the northeast to southwest trending scarp of the Western Garlock Fault strand, is present in the southeast portion of the site. The dry and moderately vegetated braided channel of Pine Tree Creek carries runoff from infrequent rainfall events from south-southwest to north-northeast across the center of the site toward Koehn Lake. An oval, paved automotive test track facility is located immediately east of the northeast quarter of the site.

Due to its location near the junction of three geomorphic provinces, the proposed BSEP site is in close proximity to several active and potentially active faults related to regional strike-slip faulting and extensional tectonics. The California Geological Survey (CGS) assigns type classifications to faults according to their historic and projected potential for future activity. 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. Type A and B faults within 70 miles of the site are listed in **Geology and Paleontology Table 2**, along with the orientation, type, sense of movement, and distance from the project site.

The fault characteristics information listed was derived from Blake, (2000), CGS, (2002 a and b), USGS (2006), and McGill and Sieh (1993). The CGS does not currently recognize the central strand of the Garlock Fault, but most recent studies indicate it is the only segment of the Garlock Fault which shows Holocene movement. The western segment may be undergoing a seismic creep (Pampeyan, Holzer, and Clark, 1988). Staff has assigned the central segment classification Type A based of its reported slip rate of 5 to 7 mm per year (McGill and Sieh, 1993), and potential to produce a magnitude 7.0 or greater earthquake (McGill and Rockwell, 1998). If the western and eastern segments of the Garlock Fault have the slip rates and maximum magnitudes assigned them by the CGS (2002), they too could be considered to be Type A faults.

Geology and Paleontology Table 2
Active Faults Relative to the Proposed BSEP Site

Fault Name	Distance From Site (miles)	Maximum Earthquake Magnitude (Mw)	Estimated Peak Site Acceleration (g)	Movement and Strike	Slip Rate mm/yr	Fault Type
Garlock - West Strand (Also known as the Cantil Fault)	0.0	7.3	0.705	Left-Lateral Strike Slip (East)	6.0	B
Garlock – Central Strand (Includes El Paso Fault)	0.9	7.3	0.705	Left-Lateral Strike Slip (Northeast)	5 - 11	A
Garlock - East Strand	62	7.5	0.691	Left-Lateral Strike Slip (Northeast)	7.0	B
Owl Lake	68.5	6.5	0.046	Left-Lateral Strike Slip	2.0	B
Lenwood-Lockhart-Old Woman Springs	14.3	7.5	0.260	Right-Lateral Strike Slip (Northwest)	0.6	B
Southern Sierra Nevada	18.3	7.3	0.237	Normal (North to Northeast)	0.1	B
White Wolf	22.1	7.3	0.205	Left-Lateral Reverse/Oblique Slip (South)	2.0	B
Gravel Hills-Harper Lake	31.4	7.1	0.116	Right-Lateral Strike Slip (Northwest)	0.6	B
Helendale-South Lockhart	31.6	7.3	0.128	Right-Lateral Strike Slip (Northwest)	0.6	B
Little Lake	34.7	6.9	0.097	Right-Lateral Strike Slip (Northwest)	0.7	B
Blackwater	36.5	7.1	0.104	Right-Lateral Strike Slip (Northwest)	0.6	B
San Andreas (Entire M-1a)	46.4	8.0	0.138	Right-Lateral Strike Slip (Northwest)	34.0	A

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 Andreas (Mojave M-1c-3)	46.4	7.4	0.101	Right-Lateral Strike Slip (Northwest)	30.0	A
San Andreas (Cholame-Mojave)	46.4	7.8	0.125	Right-Lateral Strike Slip (Northwest)	34.0	A
San Andreas (Carrizo)	47.4	7.4	0.099	Right-Lateral Strike Slip (Northwest)	34.0	A
Tank Canyon	49.2	6.4	0.069	Normal (Northwest)	1.0	B
Pleito Thrust	53.6	7.0	0.089	Reverse (Northeast)	2.0	B
Sierra Madre (San Fernando)	60.5	6.7	0.069	Reverse (North)	2.0	B
Panamint Valley	60.9	7.4	0.082	Right-Lateral Normal Oblique Slip (Northwest)	2.5	A
San Gabriel	61.1	7.2	0.073	Right-Lateral Strike Slip (Northwest)	1.0	B
Sierra Madre	62.0	7.2	0.088	Reverse (West)	2.0	B

The deepest well drilled in the site vicinity ends in alluvium at approximately 4,920 feet below surface. Gravity modeling suggests the valley is filled with sediments to a depth of approximately 10,500 feet and seismic reflection profiles suggest the basin alluvial fill may be as much as 13,000 feet deep (McGill and Rockwell, 1998). Valley fill deposits within enclosed desert basins tend to vary greatly in thickness, composition, and lateral distribution because they are generally deposited rapidly during short-lived runoff events of variable magnitude. This makes basin-wide correlation of deposits from individual runoff events an impractical if not impossible task and basin fill deposits are generally only referred to by their relative age if it can be determined by fossil, geomorphic, or other means.

The surface areas of the proposed plant site, which were disturbed by agricultural activities, are characterized by fine to coarse sand and subangular to subrounded fine to coarse gravel cover which may be the result of wind erosion of the fine-grained silt component. Subsurface investigation by Kleinfelder (2008) indicates the near surface formation is composed of sand and silt dominated layers with a minor clay component in scattered locations.

Ground water depth in the area is 304 to 487 feet below ground surface (Kleinfelder, 2007). The end of local irrigation in the mid-1980’s probably slowed or stopped ground water overdraft in the Fremont Valley. Therefore, ground water levels in the valley may be slowly rising as annual recharge replenishes the aquifer(s) beneath the site.

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 paleontological resources in the area.

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

No federal LORS concerning geologic hazards and geologic and mineralogic resources apply to this proposed 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, hydrocompaction, subsidence, expansive soils, landslides, tsunamis, and seiches.

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 paleontological information and requested records searches from the San Bernardino County Museum and the Natural History Museum of Los Angeles County for the site area. Site-specific information generated by the applicant for the BSEP was also reviewed. All research was conducted in accordance with accepted assessment protocol (SVP 1995) to determine whether any known paleontological 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 project's approval.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Ground shaking and fissuring due to subsidence settlement represent the main geologic hazards at this site. These potential hazards can be effectively mitigated through facility design by incorporating recommendations contained in the project geotechnical report. Further investigation of the power block site is necessary to verify subsurface fissuring which could affect foundation stability is not present in that area. Proposed Conditions of Certification **GEO-1**, **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 BSEP site is not located within an established Mineral Resource Zone (MRZ) and no economically viable mineral deposits are known to be present. A test pit, which was excavated to explore the potential for clay montmorillonite production, is present near SR-14 and the UPRR tracks near the northwest corner of the site but no montmorillonite production is known to have occurred (CGS, 1999).

No important paleontological resources were observed on the proposed BSEP site during the paleontological field survey conducted for the AFC (BS 2008a). The site near-surface formation is composed to an unknown and probably variable depth by unconsolidated Holocene flood plain and fan deposits. Given their recent age (<10,000 years), these deposits are unlikely to contain significant paleontological resources. Older Quaternary alluvium of Pleistocene age which underlies the Holocene deposits is known to contain significant fossil resources, primarily terrestrial vertebrates. Likewise, lakebed deposits which range in age from recent to Pleistocene have potential to contain significant fossil resources, particularly as they increase in age with depth.

Overall, staff considers the probability that paleontological resources will be encountered during site construction activities to be low. However, if construction includes significant amounts of grading or deep foundation excavation and utility trenching, the potential for exposure of paleontological resources will increase with depth of the excavations. This assessment is based on SVP criteria and the paleontological report appended to the AFC (BS 2008a). 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 paleontological resource specialist, or 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 paleontological resources.

Based on the information below, it is staff’s opinion that the potential for significant adverse, direct or indirect impacts to the project, from geologic hazards, and to potential geologic, mineralogic, and paleontological resources, from the proposed project, is low.

GEOLOGICAL HAZARDS

The AFC provides documentation of potential geologic hazards at the proposed BSEP plant site, including site-specific subsurface information (Kleinfelder, 2008). 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 subsidence are followed. Geologic hazards related to seismic shaking and subsidence are addressed in the project geotechnical report per CBC (2007) requirements (Kleinfelder, 2008). As a proposed Condition of Certification (**GEO-1**), staff recommends that examination of the near surface formation in the power block area be conducted during construction to verify the absence of splay faults or fissures which could affect the integrity of foundations. Likewise, a geologist experienced in recognition and examination of faults and fissures should be available during trenching performed during construction of the ancillary facilities, particularly the natural gas pipeline, to document any potential near surface soil anomalies and facilitate any appropriate changes in design.

Staff's independent research included the review of available geologic maps, reports, and related data of the BSEP plant site. Geological information was available from the CGS, California Division of Mines and Geology (CDMG, now know as CGS), the U.S. Geological Survey (USGS), the American Geophysical Union, the Geologic Society of America, and other organizations.

Faulting and Seismicity

Energy Commission staff reviewed numerous CDMG and USGS publications as well as informational websites 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 of the BSEP site are listed in Table 1. 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 BSEP site are summarized in **Geology and Paleontology Table 2**.

Type C and otherwise undifferentiated faults which are more than 20 miles from the site are not discussed here because they are unlikely to undergo movement or generate seismicity which could affect the project.

Although 20 Type A and B faults and fault segments were identified within 70 miles of the site, the closest and most likely to impact operation of the BSEP are the central and western segments of the Garlock Fault System. The Garlock Fault is one of the major fault systems in southern California, marking the geographic boundary between the Mojave Desert geomorphic province and, in the project area, the southern end of the Sierra Nevada geomorphic province and, further north, the Basin and Range geomorphic province. Overall, the fault system is defined as an approximately 155 mile long arcuate left lateral strike slip system extending from the San Andreas Fault at the Transverse Ranges in the south, northeast and then east to the Avawatz Mountains at the southern end of Death Valley (McGill and Sieh, 1993).

The U.S. Geological Survey and other organizations recognize three separate segments along the Garlock Fault System as they are defined by geographic setting and apparent seismic activity. These are the western, central, and eastern Garlock Fault segments. The western segment extends northeast from the San Andreas Fault at the base of the Transverse Ranges to a point just north of the project area on the eastern side of Koehn Lake. Within Fremont Valley, the Garlock Fault offsets to the west across the width of the valley to form the southwestern end of the central segment. This means much of the Fremont Valley, including the BSEP site and Koehn Lake, lies in an approximately 2-mile-wide, down-to-the-north block formed by the extensional step-over between the western and central segments (McGill and Rockwell, 1998). The central segment originates on the west side of Fremont Valley and arcs northeast approximately 65 miles to a splayed en-echelon hinge zone at the southern end of the Quail Mountains which defines the northeastern end of the central fault segment. South of the Quail Mountains the Garlock Fault bends 15 degrees to the east and the eastern segment strikes nearly east-west for 34 miles to terminate at the southern end of Death Valley (McGill and Rockwell, 2003).

Although the fault has not produced any large historic earthquakes, geomorphic and stratigraphic evidence indicates it has done so in the past and approximately 30 to 40 miles of left lateral offset has been documented along the fault since its activation during the late Miocene approximately 7 million years (My) ago (Dawson, McGill, and Rockwell, 2003). The most recent documented fault movement occurred along the Central Garlock Fault segment northwest of the project site between approximately 200 to 550 years before present (McGill and Rockwell, 1998). Although the western segment forms a prominent scarp across the southeast portion of the site, no Holocene movement has been documented on the western segment of the Garlock fault.

Holocene movement has been demonstrated on the central segment of the Garlock fault (Dawson, McGill, and Rockwell, 2003, and McGill and Sieh, 1991). In the area of Koehn Lake, approximately 5 miles north of the site, at least 5 and possibly as many as 8 surface ruptures have been recorded on the central Garlock fault in the last 5,000 years. The average recurrence rate is apparently irregular but is believed to be in the range of 700 to 1,200 years (McGill and Rockwell, 1998).

The Alquist-Priolo Act of 1973 and subsequent California state law (California Code of Regulations 2001) require that all occupied structures be set back 50 feet or more from the surface trace of an active fault. The western segment of the Garlock Fault is traceable across the southeast portion of the site, forming a topographic rise from southwest to northeast. Therefore, occupied structures will require set backs of at least 50 feet from the surface trace of the fault. Trenching should be performed beneath or near the footprint of any proposed occupied structure to demonstrate no fault splay or subsurface fissure underlies the building.

Based on previous drilling and on the soil profile generated for this site by the geotechnical investigation, the site soil class is assumed to be seismic Class D. The estimated peak horizontal ground acceleration for the power plant is 0.85 times the acceleration of gravity (0.85g) for bedrock acceleration based on 2 percent probability of exceedence in 50 years under 2007 CBC criteria. For a Class D site, the soils profile amplifies the acceleration of the ground surface to 1.94g (USGS 2008).

Liquefaction

Liquefaction is a condition in which a saturated cohesionless soil may lose shear strength because of sudden increase in pore water pressure caused by an earthquake. However, the potential for liquefaction of strata deeper than approximately 40 feet below surface is considered negligible due to the increased confining pressure and because geologic strata at this depth are generally too compact to liquefy. The reported deep ground water table of greater than 300 feet would indicate no potential for liquefaction and standard penetration testing (blowcounts) reported in the project-specific geotechnical report (Kleinfelder, 2008) indicate strata beneath the site are generally too dense to liquefy.

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 BSEP site is not subject to liquefaction, the potential for lateral spreading of the site surface during seismic events is 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. Site specific geotechnical investigation indicates the alluvial deposits in the site subsurface are generally too dense to allow significant dynamic compaction (Kleinfelder, 2008).

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 flash flood. 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. Site specific geotechnical investigation indicates the subsurface alluvial deposits which underlie the site are generally too dense to experience significant hydrocompaction (Kleinfelder, 2008).

Subsidence

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. The nearest known petroleum or gas fields are located in the Great Valley roughly 60 miles west of the project site on the western side of the southern Sierra Nevada Geomorphic Province (California Department of Conservation [CDC] 2001). Site water supply will be provided by pumping from existing wells at the site but is not expected to rival historic pumping levels. Therefore, subsidence due to petroleum, natural gas, or future ground water production is considered very unlikely.

Local subsidence or settlement may occur when areas containing compressible soils are subjected to foundation loads. Site-specific geotechnical investigation indicates the alluvial deposits which underlie the site are generally compacted to a medium-dense to very dense consistency and therefore are considered unlikely to support site-wide subsidence due to foundation loading. Deep foundations (drilled shafts) or mat foundations may be necessary to limit settlement of heavily loaded structures (Kleinfelder, 2008).

Tension cracking due to either historic ground water withdrawals, lateral extension between the western and central segments of the Garlock Fault, or possibly a combination of the two forces has resulted in formation of near-surface tension cracking and fissures in the site area in the past (Pampeyan, Holzer, and Clark, 1988; and BS 2008a). Near surface fissuring related to the Garlock Fault has also been documented near the eastern end of the Central Segment (Zellmer, Roquemore, and Blackerby, 1985). In the site area surface fissures appear to form when runoff from storm events causes erosion along the plane of tension cracks. Surface fissures can grow to several yards in width and depth and have caused historic damage to roads, power lines, and buried pipelines (Pampeyan, Holzer, and Clark, 1988). Additional examination of the near surface formation in the power block area should be conducted during construction to verify near surface soil stability and the absence of faults, tension cracks, or fissures which could fail and affect the integrity of power block structures (refer to proposed Condition of Certification **GEO-1**). A geologist experienced in recognition and examination of faults and fissures should be available during trenching performed for construction of the ancillary facilities, particularly the natural gas pipeline, to document any potential near surface soil anomalies and facilitate any appropriate changes in design (refer to proposed **GEO-1**).

Expansive Soils

Soil expansion occurs when clay-rich soils with an affinity for water exist in place at a moisture content below their plastic limit. The addition of moisture from irrigation, precipitation, capillary tension, water line breaks, etc. causes the clay soils to absorb water molecules into their structure, which in turn causes an increase in the overall volume of the soil. This increase in volume can correspond to excessive movement (heave) of overlying structural improvements. The silts and silty sand which form most of the site subsurface are not considered to be expansive.

Landslides

The BSEP site under consideration slopes gently to the east-northeast at a gradient of less than 1 percent. Due to the low site gradient and the absence of topographically high ground in the site vicinity there is no potential for landslide impacts to the proposed project.

Flooding

The Federal Emergency Management Agency (FEMA) has identified the majority of the BSEP site and ancillary facilities areas as lying in Unshaded Zone C, or “Areas of Minimal Flooding.” However, the zone along Pine Tree Creek which passes through the site from southwest to the northeast toward Koehn Lake is classified Zone A, “Areas of 100 year flood, base flood elevation and flood hazard not determined” (FEMA 1986).

Tsunamis and Seiches

The proposed BSEP project and associated linear facilities are not located near any significant surface water bodies and therefore there is no potential for impacts due to tsunamis and seiches.

GEOLOGIC, MINERALOGIC AND PALEONTOLOGICAL RESOURCES

Energy Commission staff has reviewed applicable geologic maps, reports, and on-line resources for this area (Blake 2000; Bryant 2000a and 2000b; CDMG 2003, 1999, 1998, 1994, 1990, 1986, 1965, and 1962; CGS 1999; Morton and Troxel 1962;). Staff did not identify any geological or mineralogical resources at the proposed energy facility location.

Energy Commission staff reviewed the paleontological resources assessment in Section 5.9 and Appendix H of the AFC (ENSR 2008). Staff has also reviewed paleontological literature and records searches conducted by the San Bernardino County Museum (Scott 2008) and the Natural History Museum of Los Angeles County (McCleod 2008). No paleontological resources have been documented on the proposed BSEP plant site.

Although Quaternary alluvial and lakebed deposits, like those which underlie the project site, are known to contain a wide variety of vertebrate fossils, none have been identified at the site or within a 1-mile radius of the site. There is some potential to encounter significant vertebrate fossils if drilled shaft foundations are required to support heavily loaded structures. Any fossil brought to the surface by drilling operations would be badly disturbed and out of context as well. Given the relatively small diameter of the shaft boring (typically 18 to 48 inches), and the general scarcity of significant fossils, the chances of intersecting strata bearing significant fossils would seem remote.

This assessment is based on SVP criteria, the paleontological report appended to the AFC (BS 2008a), and the independent paleontological assessment of McLeod (2008). 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 paleontological resource specialist, or 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 paleontological resources.

Construction Impacts and Mitigation

The design-level geotechnical investigation, required for the project by the CBC (2007) and proposed Condition of Certification **GEN-1**, should provide standard engineering design recommendations for mitigation of earthquake ground shaking and excessive settlement (see **Proposed Conditions of Certification, Facility Design**). Proposed Condition of Certification **GEO-1** is intended to verify that fault splays and fissures do not underlie the major structural components of the proposed project and that any such features are identified along project linears so that appropriate design precautions can be taken.

As noted above, no viable geologic or mineralogic resources are known to exist in the vicinity of the BSEP construction site. No paleontological resources have been identified at the site although older alluvium and lakebed deposits beneath the site are considered to have a high sensitivity for paleontological impacts. Construction of the proposed project will include grading, foundation excavation, and utility trenching. Based on the soils profile, SVP assessment criteria, and the depth of the potentially fossiliferous geologic units, staff considers the probability of encountering paleontological resources to be low unless drilled shaft foundation borings, or other excavations, reach greater than 25 feet below existing ground surface. Given the small diameter of the foundation borings (24 inches), and the general scarcity of significant fossils, the chances of intersecting fossil bearing strata would seem remote. The need for other excavations to extend to depths of 25 feet or more is unlikely.

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, Conditions of Certification **PAL-1 to PAL-7** require a worker education program in conjunction with monitoring of earthwork activities by qualified professional paleontologists (paleontological resource specialist, or PRS). Earthwork is halted any time potential fossils are recognized by either the paleontologist or the worker. 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 paleontological resource specialist is retained, for the project by the applicant, to produce a monitoring and mitigation plan, conduct the worker training, and provide the monitoring. During the monitoring, the PRS can and often does 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 change of finding significant fossils. In other cases, the PRS can propose increased monitoring due to unexpected fossil discoveries or in response to repeated out-of-compliance incidents by the earthwork contractor.

Based upon the literature and archives search, field surveys, and compliance documentation for the BSEP, the applicant has proposed monitoring and mitigation measures to be followed during the construction of the project. Energy Commission staff believes that the facility can be designed and constructed to minimize the effect of geologic hazards and impacts to potential paleontological resources at the site during project design life.

Operation Impacts and Mitigation

Operation of the proposed solar generating facility should not have any adverse impact on geologic, mineralogic, or paleontological resources.

CUMULATIVE IMPACTS AND MITIGATION

The proposed BSEP is situated in a seismically active geologic environment. Strong ground shaking potential must be mitigated through foundation and structural design as required by the CBC (2007). Compressible soils and areas within and near building footprints which may undergo subsidence due to tension cracking and fissuring must be mitigated in accordance with a design-level project geotechnical investigation and proposed Conditions of Certification **GEO-1**, **GEN-1, GEN-5, and CIVIL-1** under **Facility Design**. Paleontological resources have been documented in the general area of the project and in sediments similar to those that are present on the site. However, to date, none have been found during field studies of the BSEP site. The potential impacts to paleontological resources due to construction activities would be mitigated as required by proposed Conditions of Certification **PAL-1 to PAL-7**.

Staff believes that the potential for significant adverse impacts to the proposed project from geologic hazards, during the project's design life, is low, and that the potential for cumulative impacts to geologic, mineralogic, and paleontological resources is very low.

Based upon the literature and archives search, field surveys, and compliance documentation for the planned BSEP project, the applicant proposes monitoring and mitigation measures for construction of the BSEP, and staff agrees with the applicant that the project can be designed and constructed to minimize the effects of geologic hazards at the site and that impacts to fossils encountered during construction would be mitigated to levels of insignificance.

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 paleontological resources.

FACILITY CLOSURE

Facility closure activities are not expected to impact geologic, paleontological, 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 paleontological 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 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 applicant will easily be able to comply with applicable LORS, provided that the proposed Conditions of Certification are adopted and followed. The design and construction of the project should have no adverse impact with respect to geologic, mineralogic, and paleontological 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 **GEO-1**, below, and **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 paleontological resources is low at the plant site. Staff will consider reducing monitoring intensity, at the recommendation of the project paleontological resource specialist, following examination of sufficient, representative deep excavations.

GEO-1 The project owner shall have all trenching for underground utilities located within 500 feet of a known active or potentially active fault examined by a licensed geologist. The faults to be examined are:

- Garlock Fault East
- Garlock Fault West
- Randsburg-Mojave Fault
- Muroc Fault.

In addition, the foundation excavations for occupied structures, the turbine-generators, and steam generator shall be similarly examined. The purpose of the examination will be to verify the absence or presence of splay or fissures related to the major fault systems in the areas described. Fissures and/or fault splays, if present, may require mitigation in accordance with supplementary recommendations from the project geotechnical and structural engineers.

Verification: The geologist shall submit, to the CPM, appropriate, brief field reports describing and documenting his/her findings and interpretation. Any recommendations for mitigation developed by the geologist, geotechnical or structural engineers must also be submitted for review.

PAL-1 The project owner shall provide the compliance project manager (CPM) with the resume and qualifications of its paleontological resource specialist (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 Society of Vertebrate Paleontology (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. Paleontological resource monitors (PRMs) 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 paleontological resources monitoring and mitigation plan (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 Society of Vertebrate Paleontology (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 during the project kick off for those mentioned above. Following initial training, a CPM-approved video 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 paleontological 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 script and final video to the CPM for approval if the project owner is planning to use a video for interim 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 video) 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 paleontological 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.

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**). 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. 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
Beacon Solar Energy Project (08-AFC-2)

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 Beacon Solar Energy Project (BSEP), if constructed and operated as proposed, would generate 250 megawatts (MW) (nominal net output) of electricity. The BSEP would be a solar thermal power plant proposed on an approximately 2,012-acre site in eastern Kern County, California. The project would use the concentrated parabolic trough solar thermal technology to produce electrical power using a steam turbine generator fed from a solar steam generator. The BSEP would use solar energy to generate all of its capacity. Fossil fuel (natural gas) would be used only to reduce startup time and to keep the temperature of the heat transfer fluid above its relatively high freezing point. Natural gas would be used during startup to generate approximately 25 MW of electricity for 30-60 minutes per day for an estimated total of 4,500 megawatt hours (MWH) per year. Once the plant commences generation of electricity for delivery to the electrical grid, the use of the natural gas-fired auxiliary boilers ceases and they are held in stand-by mode until auxiliary heat is again required for startup or heat transfer fluid freeze protection. Compared to the project's expected overall production rate of approximately 600,000 MWH per year, and compared to a typical natural gas-fired power plant of equal capacity, the amount of the annual power production from natural gas is insignificant.

The project would decrease reliance on fossil fuel, and would increase reliance on renewable energy resources. It would not create significant adverse effects on fossil fuel energy supplies or resources, would not require additional sources of energy supply, and would not consume fossil fuel energy in a wasteful of inefficient manner. No efficiency standards apply to this project. Staff therefore concludes that this project would present no significant adverse impacts on fossil fuel energy resources.

The BSEP, if constructed and operated as proposed, would occupy approximately five acres per MW of power output, a figure about half that of some other solar power technologies.

INTRODUCTION

FOSSIL FUEL USE EFFICIENCY

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 BSEP, 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 BSEP'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 or alternatives could eliminate those adverse impacts or reduce them to a level of insignificance.

SOLAR LAND USE EFFICIENCY

Solar thermal power plants typically consume much less fossil fuel (usually in the form of natural gas) than other types of thermal power plants. Therefore, common measures of power plant efficiency such as those described above are less meaningful. So far as Energy Commission staff can determine, methods for determining the efficiency of a solar power plant have yet to be standardized; research has uncovered no meaningful attempt to quantify efficiency. The solar power industry appears to have begun discussing the issue, but a consensus is forthcoming (CEC 2008d). In the absence of accepted standards, staff proposes the following approach.

Solar thermal power plants convert the sun's energy into electricity in three basic steps:

- Mirrors and/or collectors capture the sun's rays.
- This solar energy is converted into heat.
- This heat is converted into electricity, typically in a heat engine such as a steam turbine generator or a Stirling Engine-powered generator.

The effectiveness of each of these steps depends on the specific technology employed; the product of these three steps determines the power plant's overall solar efficiency. The greater the project's solar efficiency, the less land the plant must occupy to produce a given power output.

The most significant environmental impacts caused by solar power plants result from occupying large expanses of land. Even in a desert environment, disturbing and shading hundreds or thousands of acres of land can impact environmental resources. The extent of these impacts is likely in direct proportion to the number of acres affected. For this reason, staff will evaluate the land use efficiency of proposed solar power plant projects. This efficiency will be expressed in terms of power produced, or MW per acre, and in terms of energy produced, or MW-hours per acre-year. Specifically:

- Power-based solar land use efficiency is calculated by dividing the maximum net power output in MW by the total number of acres impacted by the power plant, including roads and electrical switchyards and substations.
- Energy-based solar land use efficiency is calculated by dividing the annual net electrical energy production in MW-hours per year by the total number of acres impacted by the power plant. Since different solar technologies consume differing quantities of natural gas for morning warm-up, cloudy weather output leveling and heat transfer fluid freeze protection (and some consume no gas at all), this effect will be accounted for. Specifically, gas consumption will be backed out by reducing the

plant’s net energy output by the amount of energy that could have been produced by consuming the project’s annual gas consumption in a modern combined cycle power plant. (See **Efficiency Appendix A**, immediately following.) This reduced energy output will then be divided by acres impacted.

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

The applicant proposes to build and operate the BSEP, a solar thermal power plant producing a total of 250 MW (nominal net output) and employing the concentrated parabolic trough solar thermal technology. The project would consist of arrays of parabolic mirrors, solar steam generator heat exchangers, one steam turbine generator, and a wet cooling tower (BS 2008a, AFC §§1.1, 2.1, 2.5).

The project’s power cycle would be based on a steam cycle (also known as the Rankine cycle) (BS 2008a, AFC §2.5.2).The solar steam generator heat exchangers would receive heated heat transfer fluid from the solar thermal equipment comprised of arrays of parabolic mirrors that collect energy from the sun. The heated heat transfer fluid would be used to generate steam in the heat exchangers. This steam would then expand through the steam turbine generator to produce electrical power.

The project would utilize two auxiliary boilers fueled by natural gas to reduce startup time and to keep the temperature of the heat transfer fluid above its relatively high freezing point (54 degrees Fahrenheit). Except during startup, the project would not use fossil fuel to generate electricity.

ASSESSMENT OF IMPACTS — FOSSIL FUEL ENERGY USE

METHOD AND THRESHOLD FOR DETERMINING THE SIGNIFICANCE OF FOSSIL FUEL 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

The BSEP would consume no natural gas or other fossil fuel for power generation. It would consume natural gas only to reduce startup time and to keep the temperature of the heat transfer fluid above its relatively high freezing point.

The project would burn natural gas at a nominal rate of approximately 60 million British thermal units (MMBtu) per hour lower heating value (LHV), for a total annual consumption of 36,000 MMBtu LHV (BS 2008a, AFC §§2.5.2, 2.5.5.1). Compared to a typical natural gas-fired power plant of equal capacity, this rate is insignificant.

The applicant estimates an average overall steam cycle efficiency of 35 percent for the BSEP (BS 2008a, AFC Figure 2-7). There are currently no legal or industry standards for measuring the efficiency of solar thermal power plants (CEC 2008d). Therefore, staff compares the steam cycle efficiency of the BSEP to the average efficiency of the typical modern steam turbines currently available in the market. The efficiency figures for these turbines range from 35 percent to 40 percent. The project's thermal efficiency of 35 percent is comparable to this industry figure.

Therefore, staff considers the impact of the project's fuel consumption on energy supplies and energy efficiency to be less than significant.

ADVERSE EFFECTS ON ENERGY SUPPLIES AND RESOURCES

The applicant has described its sources of natural gas for the project (BS 2008a, AFC §§2.1, 2.3, 2.5.5.1, 2.6). Natural gas would be delivered to the BSEP site via a new 17.6-mile-long, 8-inch diameter natural gas distribution pipeline that would be connected to an existing Southern California Gas Company (SCG) pipeline. Natural gas would be used to reduce startup time and to keep the temperature of the heat transfer fluid above its freezing point.

The SCG natural gas system has access to gas from the Rocky Mountains, Canada and the southwest. This represents a resource of considerable capacity, an adequate source for the BSEP. This system is capable of delivering the natural gas that the BSEP would require; it constitutes a reliable source of natural gas for this project. The BSEP would consume much less natural gas than a typical natural gas-fired power plant of equal capacity. Therefore, it appears highly unlikely that the project would create a substantial increase in natural gas demand.

ADDITIONAL ENERGY SUPPLY REQUIREMENTS

Natural gas would be supplied to the project by the SCG via a new natural gas pipeline (BS 2008a, AFC §§2.1, 2.3, 2.5.5.1, 2.6). There appears to be little likelihood that the BSEP would require additional supply.

COMPLIANCE WITH ENERGY STANDARDS

No standards apply to the efficiency of the BSEP or other non-cogeneration projects.

ALTERNATIVES TO REDUCE WASTEFUL, INEFFICIENT, AND UNNECESSARY ENERGY CONSUMPTION

Staff evaluates the project alternatives to determine if alternatives exist that could reduce the project's fuel use. The evaluation of alternatives to the project (that could reduce wasteful, inefficient, or unnecessary energy consumption) requires the examination of the project's energy consumption. Even though staff does not believe the project's fuel consumption would be significant, staff evaluates alternatives that could reduce or eliminate the use of natural gas.

Efficiency of Alternatives to the Project

The BSEP's objectives include the generation of electricity using the concentrated parabolic trough solar thermal technology (BS 2008a, AFC §2.2).

Alternative Generating Technologies

Alternative generating technologies for the BSEP are considered in the AFC (BS 2008a, AFC §§1.3, 4.6) and the section of this document entitled **Project Alternatives**. For purposes of this analysis, natural gas, oil, coal, nuclear, biomass, hydroelectric,wind, and other solar technologies are all considered. Employing the AUSRA Compact Linear Fresnel Reflector technology would increase the land use efficiency. The AUSRA technology, however, is relatively new while the the concentrated parabolic trough solar thermal technology proposed to be employed in the BSEP has been employed for over 20 years.

Employing the photovoltaic (PV) technology would result in a lower land use efficiency than the technology proposed for the BSEP. A proposed 550 MW power plant employing the PV technology, the Topaz Solar Farm (TSF), is expected to occupy 6,200 acres (TSF 2008). The land use efficiency of the TSF would be 0.09, as compared to 0.19 expected by the BSEP as seen in **Efficiency Table 1**.

Given the project objectives, location, air pollution control requirements, and the commercial availability of the above technologies, staff agrees with the applicant that the selected solar thermal technology is a feasible selection.

Staff, therefore, believes that the BSEP would not constitute a significant adverse impact on fossil fuel energy resources compared to feasible alternatives.

ASSESSMENT OF IMPACTS — SOLAR LAND USE

The solar insolation falling on the earth's surface can be regarded as an energy resource. Since this energy is inexhaustible, its consumption does not present the concerns inherent in fossil fuel consumption. What is of concern, however, is the extent of land area required to capture this solar energy and convert it to electricity. Setting aside hundreds or thousands of acres of land for solar power generation removes it from alternative uses. Constructing buildings and solar collector foundations can disturb environmental resources.

As discussed above, Energy Commission staff is unaware of any accepted standard for evaluating the efficiency of a solar power plant such as the BSEP. Accordingly, staff proposes to tabulate the land use efficiency of the project (described above) and compare it to similar measures for other solar power plant projects that have passed through, or are passing through, the Energy Commission's siting process.

METHOD AND THRESHOLD FOR DETERMINING THE SIGNIFICANCE OF SOLAR LAND USE ENERGY RESOURCES

Energy Commission staff proposes to compare the land use of a solar power plant project to that of other solar projects in the Energy Commission's siting process. It has not been determined how great a difference in land use would constitute a significant difference; staff proposes to compare the five solar projects currently in the process.

As this is written, there are currently five solar power plant projects in the Energy Commission siting process. These projects' power and energy output, and the extent of the land occupied by them, are summarized in **Efficiency Table 1**, below. The solar land use efficiency for a typical natural gas-fired combined cycle power plant is shown only for comparison.

ADVERSE EFFECTS ON LAND USE

While the Energy Commission customarily requires full mitigation for such impacts, such mitigation is generally regarded as less effective in protecting resources than avoiding the impact entirely. A solar power project that occupies twice as much land as another project holds the potential to produce twice the environmental impacts.

PROJECT LAND USE

The BSEP would produce power at the rate of 250 MW net, and would generate energy at the rate of 600,000 MW-hours net per year, while occupying approximately 1,321 acres (the portion of the 2,012-acre site encompassing the solar field, the power block, the evaporation ponds, and the administration buildings[1]) (BS 2008a, AFC §§2.3, Figure 2-4). Staff calculates power-based land use efficiency thus:

[1] 1,266 + 55 = 1,321
Solar field plus power block = 1,266 acres
Staff's estimate of the footprint encompassing the evaporation ponds and administration buildings = 55 acres (BS 2008a, AFC Figure 2-4). The remainder of the 2,012 acres is for access to natural gas, transmission lines and local roads, not the land necessary to generate power or operate the power plant.

Power-based efficiency: 250 MW ÷ 1,321 acres = **0.19 MW/acre** or **5.3 acres/MW**
Staff calculates energy-based land use efficiency thus:

Energy-based efficiency: 600,000 MWh/year ÷ 1,321 acres = **454 MWh/acre-year**

As seen in **Efficiency Table 1**, the BSEP, employing the linear parabolic trough technology, is roughly twice as efficient in use of land as the Ivanpah SEGS project, which employs BrightSource power tower technology, the Stirling Energy Systems Solar One project, and the Stirling Energy Systems Solar Two project; and is roughly 32 percent less efficient than the Carrizo Energy Solar Farm project in use of land, which employs the AUSRA Compact Linear Fresnel Reflector technology.

ALTERNATIVES TO REDUCE SOLAR LAND USE IMPACTS

Building and operating a natural gas-fired combined cycle power plant would yield much greater land use efficiency than any solar power plant; see **Efficiency Table 1**. However, this would not achieve the basic project objective, to generate electricity from the renewable energy of the sun.

Efficiency Table 1 — Solar Land Use Efficiency

Project	Generating Capacity (MW net)	Annual Energy Production (MWh net)	Annual Fuel Consumption (MMBtu LHV)	Footprint (Acres)	Land Use Efficiency (Power-Based) (MW/acre)	Land Use Efficiency (Energy – Based) (MWh/acre-year)	
						Total	Solar Only[2]
Beacon Solar (08-AFC-2)	250	600,000	36,000	1,321	0.19	454	450
Carrizo Energy (07-AFC-8)	177	375,000	0	640	0.28	586	586
Ivanpah SEGS (07-AFC-5)	400	960,000	432,432	3,744	0.11	256	238
SES Solar One (08-AFC-13)	850	1,840,000	0	8,200	0.11	224	224
SES Solar Two (08-AFC-5)	750	1,620,000	0	6,500	0.12	249	249
Avenal Energy (08-AFC-1)[3]	600	3,023,388	24,792,786	25	24.0	120,936	N/A

[2] Net energy output is reduced by natural gas-fired combined cycle proxy energy output; see **Efficiency Appendix A**.

[3] Example natural gas-fired combined cycle plant.

Building a solar power plant employing a different technology, such as the BrightSource power tower technology of the Ivanpah SEGS project or the Stirling Engine technology of the SES Solar projects, would almost halve the solar land use efficiency of the BSEP. This would likely almost double the land use-based environmental impacts brought about by the project. Employing the AUSRA Compact Linear Fresnel Reflector technology would increase the land use efficiency. The AUSRA technology, however, is relatively new while the the concentrated parabolic trough solar thermal technology proposed to be employed in the BSEP has been employed for over 20 years at the nearby Solar Electric Generating System facilities in the Mojave Desert (BS 2008a, AFC §§1.3, 2.5.3.1). Staff believes the BSEP represents one of the most land use-efficient solar technologies currently available to satisfy the project objective of using proven solar thermal technology.

Alternative Heat Rejection System

The applicant proposes to employ a wet cooling system (an evaporative cooling tower) as the means for rejecting power cycle heat from the steam turbine (BS 2008a, AFC §§1.1, 1.3, 2.5.1, 2.5.2). An alternative heat rejection system would utilize an air-cooled condenser.

The local climate in the project area is characterized by high temperatures and low relative humidity (low wet-bulb temperature). In low temperatures and high relative humidity (low dry-bulb temperature), the air-cooled condenser performs relatively efficiently compared to the evaporative cooling tower. However, at the project area (low wet-bulb temperature and high dry-bulb temperature) the air-cooled condenser performance is relatively poor compared to that of an evaporative cooling tower. Furthermore, the performance of the heat rejection system affects the performance of the steam turbine, impacting turbine efficiency. Compared with dry cooling, wet cooling would slightly improve the turbine efficiency at the BSEP site. Thus, from an efficiency perspective, staff believes the wet cooling technology selected for this project is a viable selection.

CUMULATIVE IMPACTS

There are no nearby power plant projects or other projects consuming large amounts of natural gas that hold the potential for cumulative energy consumption impacts when aggregated with the project.

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. Because the BSEP would consume significantly less natural gas than a typical natural gas-fired power plant, it should compete favorably in the California power market and replace fossil fuel burning power plants. The project would therefore cause a positive impact on the cumulative amount of natural gas consumed for power generation.

NOTEWORTHY PUBLIC BENEFITS

The BSEP would employ an advanced solar thermal technology. Solar energy is renewable and unlimited. The project would have a less than significant adverse impact on nonrenewable energy resources (natural gas). Consequently, the project would help in reducing California's dependence on fossil fuel-fired power plants.

CONCLUSIONS AND RECOMMENDATIONS

FOSSIL FUEL ENERGY USE

The BSEP, if constructed and operated as proposed, would use solar energy to generate most of its capacity, consuming insignificant amounts of natural gas for power production. Natural gas would be used only to reduce startup time and to keep the temperature of the heat transfer fluid above its relatively high freezing point. The project would decrease reliance on fossil fuel, and would increase reliance on renewable energy resources. 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 this project. Staff therefore concludes that this project would present no significant adverse impacts on energy resources.

No cumulative impacts on energy resources are likely. Facility closure would not likely present significant impacts on electric system efficiency.

LAND USE

The BSEP, if constructed and operated as proposed, would occupy approximately five acres per MW of power output, a figure about half that of some other solar power technologies. Employing a more land-intensive solar technology, such as the BrightSource power tower technology or Stirling Engine technology, would almost double the resultant adverse environmental impacts. Staff believes the BSEP represents one of the most land use-efficient solar technologies currently available.

PROPOSED CONDITIONS OF CERTIFICATION

No conditions of certification are proposed.

REFERENCES

BS 2008a **–** FPL Energy/M. O'Sullivan (tn 45646). Submittal of the Application for Certification for the Beacon Solar Energy Project, dated 03/13/08. Submitted to CEC/Docket Unit on 03/14/08.

CEC 2008d – Report of Conversation between Steve Baker (CEC staff, Power Plant Siting Division) and Golam Kibrya (CEC staff, Energy Resource and Development Division). February 22, 2008.

TSF 2008 – Conditional Use Permit for the Topaz Solar Farm. Submitted to San Luis Obsispo County on July 18, 2008.

Efficiency Appendix A
Solar Power Plant Efficiency Calculation
Gas-Fired Proxy

In calculating the efficiency of a solar power plant, it is desired to subtract the effect of natural gas burned for morning startup, cloudy weather augmentation and Therminol freeze protection. As a proxy, we will use an average efficiency based on several recent baseload combined cycle power plant projects in the Energy Commission siting process. Baseload combined cycles were chosen because their intended dispatch most nearly mirrors the intended dispatch of solar plants, that is, operate at full load in a position high on the dispatch authority's loading order.

The most recent such projects are:

Colusa Generating Station (06-AFC-9)
Nominal 660 MW 2-on-1 Combined Cycle with GE Frame 7FA CGTs
Air cooled condenser, evaporative inlet air cooling
Efficiency with duct burners on: 666.3 MW @ 52.5% LHV
Efficiency with duct burners off: 519.4 MW @ 55.3% LHV
Efficiency (average of these two): **53.9% LHV**

San Gabriel Generating Station (07-AFC-2)
Nominal 696 MW 2-on-1 Combined Cycle with Siemens 5000F CGTs
Air cooled condenser, evaporative inlet air cooling
Efficiency with duct burners on: 695.8 MW @ 52.1% LHV
Efficiency with duct burners off: 556.9 MW @ 55.1% LHV
Efficiency (average of these two): **53.6% LHV**

KRCD Community Power Plant (07-AFC-7)
Nominal 565 MW 2-on-1 Combined Cycle with GE or Siemens F-class CGTs
Evaporative cooling, evaporative or fogging inlet air cooling
Efficiency with GE CGTs: 497 MW @ 54.6% LHV
Efficiency with Siemens CGTs: 565 MW @ 56.1% LHV
Efficiency (average of these two): **55.4% LHV**

Avenal Energy (08-AFC-1)
Nominal 600 MW 2-on-1 Combined Cycle with GE Frame 7FA CGTs
Air cooled condenser, inlet air chillers
Efficiency with duct burners on: 600.0 MW @ 50.5% LHV
Efficiency with duct burners off: 506.5 MW @ 53.4% LHV
Efficiency (average of these two): **52.0% LHV**

Average of these four power plants: **53.7% LHV**

POWER PLANT RELIABILITY

Shahab Khoshmashrab

SUMMARY OF CONCLUSIONS

The applicant predicts an equivalent availability factor of 96 percent, which staff believes is achievable. (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.) Based on a review of the proposal, with the exception of the sources of water supply and flood protection (see the **Soil and Water Resources** section of this document), staff concludes that the Beacon Solar Energy Project (BSEP) would be built and would operate in a manner consistent with industry norms for reliable operation. No conditions of certification are proposed.

INTRODUCTION

In this analysis, California Energy Commission (Energy Commission) staff addresses the reliability issues of the BSEP 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 norm 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" subsection, 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 96 percent for the BSEP (see below), staff uses typical industry norms as the 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), that purchase, dispatch, and sell electric power throughout the state. Determining how the California ISO and other control area operators would ensure system reliability has been an ongoing effort. Protocols have been developed and put in place that allow sufficient reliability to be maintained under the competitive market system. “Must-run” power purchase agreements and “participating generator” agreements are two mechanisms that have been employed to ensure an adequate supply of reliable power.

In September 2005, California AB 380 (Núñez, Chapter 367, Statutes of 2005) became law. This modification to the Public Utilities Code requires the California Public Utilities Commission to consult with the California ISO to establish resource adequacy requirements for all load-serving entities (basically, publicly and privately owned utility companies). These requirements include maintaining a minimum reserve margin (extra generating capacity to serve in times of equipment failure or unexpected demand) and maintaining sufficient local generating resources to satisfy the load-serving entity’s peak demand and operating reserve requirements.

In order to fulfill this mandate, the California ISO has begun to establish specific criteria for each load-serving entity under its jurisdiction. These criteria guide each load-serving entity in deciding how much generating capacity and ancillary services to build or purchase, after which the load-serving entity issues power purchase agreements to satisfy these needs. According to the AFC, the BSEP has negotiated a power purchase agreement with a major California utility company (company’s name not disclosed in the AFC) (BS 2008a, AFC §2.0).

The California ISO’s mechanisms to ensure adequate power plant reliability apparently were devised under the assumption that the individual power plants that compete to sell power into the system will each exhibit a level of reliability similar to that of power plants of past decades. However, there has been valid cause to believe that, under free market competition, financial pressures on power plant owners to minimize capital outlays and maintenance expenditures may act to reduce the reliability of many power plants, both existing and newly constructed (McGraw-Hill 1994). It is possible that, if significant numbers of power plants were to exhibit individual reliability sufficiently lower than this historical level, the assumptions used by California ISO to ensure system reliability would prove invalid, with potentially disappointing results. Accordingly, staff has recommended that power plant owners continue to build and operate their projects to the level of reliability to which all in the industry are accustomed.

As part of its plan to provide needed reliability, the applicant proposes to operate the 250-megawatt (MW) (net power output) BSEP, a solar thermal power plant facility employing advanced solar power technology. This project, using renewable solar energy, would provide dependable power to the grid, generally during the hours of peak power consumption by the interconnecting utility(s). This project would help serve the need for renewable energy in California, as all its generated electricity would be produced by a reliable source of energy that is available during the hot summer afternoons, when power is needed most.

The project is expected to achieve an equivalent availability factor in the range of 96 percent. The project is anticipated to operate at an annual capacity factor of approximately 26.5 percent (BS 2008a, AFC §2.5.2).

ASSESSMENT OF IMPACTS

METHOD FOR DETERMINING RELIABILITY

The Energy Commission must make findings as to how a 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. Throughout its intended 30-year life, the BSEP is expected to operate reliably (BS 2008a, AFC §2.5.3). 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 the factors compare favorably for this project, staff will then conclude that the BSEP 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 adoption of 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.

Quality Control Program

The applicant describes a QA/QC program (BS 2008a, AFC §2.5.3) 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

The project, as proposed in the AFC, would be able to operate only when the sun is shining. Maintenance or repairs could be done when the plant is shut down at night.

This would help to enhance the project's reliability. Also, the applicant proposes to provide redundant pieces of equipment for those that are most likely to require service or repair. This redundancy would allow service or repair to be done during sunny days when the plant is in operation, if required.

Major plant systems are designed with adequate redundancy to ensure their continued operation if equipment fails.

Maintenance Program

Equipment manufacturers provide maintenance recommendations for their products, and the applicant would base the project's maintenance program on those recommendations (BS 2008a, AFC §2.5). 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 BSEP would consume insignificant amounts of natural gas or other fossil fuel for power generation. The sole consumption of natural gas would be to reduce startup time and to keep the temperature of the heat transfer fluid above its freezing point.

Natural gas would be delivered to the BSEP site via a new 17.6-mile-long, 8-inch diameter natural gas distribution pipeline that would be connected to an existing Southern California Gas Company (SCG) pipeline (BS 2008a, AFC Appendix K.3). The SCG natural gas system represents a reliable source of considerable capacity and offers access to adequate supplies of gas from the Southwest, the Rocky Mountains, and Canada. The very limited use of fuel would have minimal impact on gas supplies. Staff believes that there will be adequate natural gas supply and pipeline capacity to meet the project's needs.

Water Supply Reliability

The BSEP would use well water for domestic and industrial water needs, including steam cycle makeup, mirror washing, service water and fire protection water. Several existing groundwater wells on the project site would be used to provide the project's water needs (BS 2008a, AFC §§1.4.16, 2.5.5.2). According to the **Soil and Water Resources** section of this document, the proposed use of onsite groundwater for power plant cooling is in conflict with the State Water Board and Energy Commission policies, and the proposed use of onsite groundwater is likely to affect current and future users of potable groundwater in the project vicinity.

Therefore, at this time, staff cannot conclude that the sources proposed by the applicant 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. 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 (BS 2008a, AFC §§1.2, 2.5.6.6).

Seismic Shaking

The site lies within Seismic Zone 4 (BS 2008a, AFC §1.2); see the "Faulting and Seismicity" portion of the **Geology and Paleontology** section of this document. The project will be designed and constructed to the latest applicable LORS (BS 2008a, AFC Appendix C). Compliance with current seismic design LORS represents an upgrading of performance during seismic shaking compared to older facilities since these LORS have been 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 earthquakes.

Flooding

The project site elevation ranges from approximately 2,050 to 2,260 feet above mean sea level. According to the Federal Emergency Management Agency, a portion of the site lies within the 100-year flood plain (BS 2008a, AFC §§2.5.6.6, 5.17.2.9). According to the **Soil and Water Resources** section of this document, the diversion channel intending to reroute flood flows around the project site is not adequate for anticipated flows, and the applicant's proposed flood plan is not sufficient to mitigate the project's significant adverse impacts to less than significant. Therefore, at this time, staff cannot conclude that there are no special concerns with power plant reliability due to flooding.

For further discussion, see **Soil and Water Resources** and **Geology and Paleontology**.

COMPARISON WITH EXISTING FACILITIES

The North American Electric Reliability Corporation (NERC) maintains industry statistics for availability factors (as well as other related reliability data). The 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 at <http://www.nerc.com>. No statistics are available for solar power plants. The project's power cycle is based on the well-known Rankine steam cycle. Because natural gas is the primary type of fossil fuel used in California, staff finds it reasonable to compare the project's availability factor to the average availability factor of natural gas-fired fossil fuel units. Also, because the project's total net power output would be 250

MW, staff uses the NERC statistics for 200–299 MW units. The NERC reported an availability factor of 86.01 percent as the generating unit average for the years 2002 through 2006 for natural gas units of 200-299 MW (NERC 2007).

The concentrated parabolic trough solar thermal technology is not new. This technology has been employed for over 20 years at the nearby Solar Electric Generating System facilities in the Mojave Desert (BS 2008a, AFC §§1.3, 2.5.3.1). Staff believes that the parabolic trough technology is likely to exhibit the projected reliability.

The project would use multi-pressure condensing steam turbine technology. Steam turbines incorporating this technology have been on the market for many years now and are expected to exhibit typically high availability. Also, because solar-generated steam is cleaner than burnt fossil fuel (i.e., natural gas), the BSEP steam cycle units would likely require less frequent maintenance than units that burn fossil fuel. Therefore, the applicant's expectation of an annual availability factor of 96 percent (BS 2008a, AFC §2.5.2) appears reasonable when compared with the NERC figures throughout North America (see above). In fact, these machines might well be expected to outperform the fleet of various turbines (mostly older and smaller) that make up NERC statistics. Additionally, the project, as proposed in the AFC, would be able to operate only when the sun is shining. Maintenance or repairs could be done when the plant is shut down at night.

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 help serve the need for renewable energy in California, as most of the electricity generated would be produced by a reliable source of energy that is available during the hot summer afternoons, when power is needed most.

CONCLUSION

The applicant predicts an equivalent availability factor of 96 percent, which staff believes is achievable. Based on a review of the proposal, with the exception of the sources of water supply and flood protection (see the **Soil and Water Resources** section of this document), staff concludes that the plant would be built and operated in a manner consistent with industry norms for reliable operation. No conditions of certification are proposed.

PROPOSED CONDITIONS OF CERTIFICATION

No conditions of certification are proposed.

REFERENCES

BS 2008a—FPL Energy/M. O'Sullivan (tn 45646). Submittal of the Application for Certification for the Beacon Solar Energy Project, dated 03/13/08. Submitted to CEC/Docket Unit on 03/14/08.

McGraw-Hill 1994—McGraw-Hill Energy Information Services Group. 1994. *Operational Experience in Competitive Electric Generation*. Executive Report.

NERC 2007—North American Electric Reliability Corporation. 2007. *2002–2006 Generating Availability Report*.

TRANSMISSION SYSTEM ENGINEERING

Sudath Arachchige and Mark Hesters

SUMMARY OF CONCLUSIONS

The proposed Beacon Solar Energy Project (BSEP) outlet lines and termination are acceptable and would comply with all applicable laws, ordinances, regulations, and standards (LORS). The analysis of project transmission lines and equipment, both from the power plant up to the point of interconnection with the existing transmission network as well as upgrades beyond the interconnection that are attributable to the project have been evaluated by staff.

- The modification of the existing Barren Ridge switch yard would occur within the fence line of the existing Los Angeles Department of Water and Power (LADWP) switchyard and would not trigger CEQA (California Environmental Quality Act).
- The applicant should request a Facility Study (FS) to be performed by the LADWP to determine the cost estimates and work scope for interconnection facilities and the transmission network upgrades of the LADWP system.

INTRODUCTION

STAFF ANALYSIS

This transmission system engineering (TSE) analysis examines whether this project's proposed interconnection conforms to all LORS required for safe and reliable electric power transmission. Additionally, under 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 (Title 14, California Code of Regulations §15378). The Energy Commission must therefore identify the system impacts and necessary new or modified transmission facilities downstream of the proposed interconnection that are required for interconnection and that represent the whole of the action.

Commission staff relies upon the responsible interconnecting authority for analysis of impacts on the transmission grid, as well as for the identification and approval of new or modified facilities required downstream from the proposed interconnection for mitigation purposes.

LADWP'S ROLE

LADWP is responsible for ensuring electric system reliability in its service territory for proposed transmission modifications. For the BSEP project, LADWP performed the System Impact Study used to determine whether or not the proposed transmission modifications conform to reliability standards. Because the BSEP project would be connected to the LADWP controlled Municipal utility grid via the Barren Ridge 230kV switching station, the California LADWP's role is to review and approve the SIS and its conclusions.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

- California Public Utilities Commission (CPUC) General Order 95 (GO-95), *Rules for Overhead Electric Line Construction*, sets forth uniform requirements for the construction of overhead lines. Compliance with this order ensures both adequate service and the safety of both the public and the people who build, maintain, and operate overhead electric lines.
- CPUC General Order 128 (GO-128), *Rules for Construction of Underground Electric Supply and Communications Systems*, sets forth uniform requirements and minimum standards for underground supply systems to ensure adequate service and the safety of both the public and the people who build, maintain, and operate underground electric lines.
- The National Electric Safety Code, 1999, provides electrical, mechanical, civil, and structural requirements for overhead electric line construction and operation.
- The combined NERC/WECC (North American Electric Reliability Corporation/Western Electricity Coordinating Council) planning standards provide system performance standards for assessing the reliability of the interconnected transmission system. These standards require continuity of service as their first priority and the preservation of interconnected operation as their second. Some aspects of NERC/WECC standards are either more stringent or more specific than the either agency's standards alone. These standards are designed to ensure that transmission systems can withstand both forced and maintenance outage system contingencies while operating reliably within equipment and electric system thermal, voltage, and stability limits. These standards include reliability criteria for system adequacy and security, system modeling data requirements, system protection and control, and system restoration. Analysis of the WECC system is based to a large degree on Section I.A of WECC standards, *NERC and WECC Planning Standards with Table I and WECC Disturbance-Performance Table,* and on Section I.D, *NERC and WECC Standards for Voltage Support and Reactive Power.* These standards require that power flows and stability simulations verify defined performance levels. Performance levels are defined by specifying allowable variations in thermal loading, voltage and frequency, and loss of load that may occur during various disturbances. Performance levels range from no significant adverse effects inside and outside a system area during a minor disturbance (such as the loss of load from a single transmission element) to a catastrophic loss level designed to prevent system cascading and the subsequent blackout of islanded areas and millions of consumers during a major transmission disturbance (such as the loss of multiple 500-kV lines along a common right-of- way, and/or of multiple large generators). While the controlled loss of generation or system separation is permitted under certain specific circumstances, this sort of major uncontrolled loss is not permitted (WECC, 2002).
- NERC's reliability standards for North America's electric transmission system spell out the national policies, standards, principles, and guidelines that ensure the adequacy and security of the nation's transmission system. These reliability standards provide for system performance levels under both normal and contingency conditions. While these standards are similar to the combined NERC/WECC standards, certain aspects of the combined standards are either more

stringent or more specific than the NERC performance standards alone. NERC's reliability standards apply to both interconnected system operations and to individual service areas (NERC, 2006).

- LADWP planning standards also provide the standards and guidelines that ensure the adequacy, security, and reliability of the state's member grid facilities. These standards also incorporate the combined NERC/WECC and NERC standards. These standards are also similar to the NERC/WECC or NERC standards for transmission system contingency performance. However, the LADWP standards also provide additional requirements that are not found in either the WECC/NERC or NERC standards. The LADWP standards apply to all participating transmission owners interconnecting to the LADWP controlled grid. They also apply to non-member facilities that impact the LADWP grid through their interconnections with adjacent control grids (LADWP, SIS).

PROJECT DESCRIPTION

The proposed BSEP site is located approximately one mile to the north of LADWP's Barren Ridge 230kV switching station site and will consist of a 250MW steam turbine generator. The steam for the prime mover will be created by utilizing collected solar energy, through a heat-exchanger. The proposed generating plant will consist of one 330 MVA Steam turbine generating unit for a total net output of 250MW. The project's planned operational date is summer of 2011.The generator auxiliary load would be 30MW, resulting in a maximum net output of 250 MW at an 85 percent power factor. Generating unit would be connected to the low side of its dedicated 18/230 kV generator step-up (GSU) transformer through 18kV, 1200-ampere SF6 circuit breakers. The step-up transformer for the steam turbine generating unit would be rated at 18/230 kV and 200/266/332 megavolt ampere (MVA) at 55 centigrade. The 230-kV side of step-up transformer would be connected through 1200A, SF6 circuit breaker to the existing Barren Ridge switching station via the selected 230kV transmission line options. The applicant has proposed to utilize the existing bus work within the breaker-and- a-half Barren Ridge switching station to interconnect the BSEP plant. The modification of the existing Barren Ridge switch yard would consist of two new 3000A, 230kV circuit breakers, 230-115 kV capacitor controlled voltage transformers and four 230kV, 3000 A disconnect switches. (BSEP project, 2008b section 2.0 pages 2-29 to 2-32 and Figure 2-4,2-10,2-15, 2-16).

SWITCHYARD AND INTERCONNECTION FACILITIES

The project will interconnect to the LADWP owned Barren Ridge switching station as the primary point of interconnection. An alternate point of interconnection is proposed at a location within the project property line and adjacent to the LADWP 230kV line, approximately one mile north of the primary point of interconnection.

- The direct Barren Ridge interconnection option would require approximately 3.5 miles of overhead 230kV transmission line, approximately 1.6 miles of which would be within the plant site boundary. The line would exit a pull off structure within a new project switchyard in the plant side power block and head northerly. It will follow the project access road for approximately 1.2 miles on monopole steel concrete structures, turning southwest to cross the existing Union Pacific (UP) rail line and SR- 14. After crossing SR-14 the line will continue in a southwesterly direction for approximately 0.3 mile until it reaches the Barren Ridge switching station.

- The second option would require construction of a new 230kV BSEP switching station and a total of approximately 2.75 miles of overhead 230kV transmission lines. The line would exit a pull off structure within a new project switchyard in the plant side power block and head northerly. It will follow the project access road for approximately 1.25 miles on monopole steel concrete structures, turning southwest to cross the existing UP rail line and SR- 14. After crossing SR-14 the line will terminate on a pull-off structure within the new switching station. The new Beacon switching station would be connected to the Barren Ridge switching station via newly built 1.5 mile long 230kV single circuit. The BSEP switching station would be designed for three breaker ring bus configuration for added reliability and flexibility. The switchyard consists of 230-kV, 1200 ampere circuit breakers, 230-kV no-load disconnect switches, and other switching gear that will allow delivery of the project's output to the LAWDP 230kV grid. The ring bus configuration of the new switchyard would leave room for a loop-in of the Inyo-Barren Ridge line in the future.

On both options, the 230kV overhead single circuit would be built with 795 kcmil per phase ACSR conductors and routed through the 230kV, 36 new steel/concrete mono-poles to interconnect plant to the existing Barren Ridge substation. The proposed overhead generator tie lines are rated to carry the full capacity of the BSEP project. The 230kV poles are expected to average about 79 feet in height, with a span length expected to average approximately 500 feet. (BSEP project, 2008b section 2.0 pages 2.29, 2.32 and Figure 2-4, 2-10).The proposed transmission lines are the first point of interconnection and will be permitted by the CEC, and a general level of environmental review is required for the Energy Commission's CEQA process.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

The proposed BSEP project would deliver energy to the 230kV LADWP grid; hence LADWP municipal utility is responsible for ensuring grid reliability. This entity determines the transmission system impacts of the proposed project and any mitigation measures needed to ensure system conformance with utility reliability criteria, NERC planning standards, WECC reliability criteria. System impact and facilities studies are used to determine the impacts of the proposed project on the transmission grid. Staff relies on these studies and any review conducted by the LADWP to determine the effect of the project 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. System impact and facilities studies analyze the grid both with and without the proposed project, 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 through which grid reliability is determined. The studies analyze the impact of the project for the proposed first year of operation, and are based on a forecast of loads, generation, and transmission. Load forecasts are developed by the interconnected utility. Generation and transmission forecasts are established by an interconnection queue. The studies focus on thermal overloads, voltage deviations, system stability (excessive oscillations in generators and transmission system, voltage collapse, loss of loads, or cascading outages), and short circuit duties. If the studies show that the interconnection of the project causes the grid to be out of compliance with reliability standards, then the study will identify mitigation alternatives or ways in which the grid could be brought into compliance with reliability standards.

When a project connects to the LADWP-controlled grid, both the studies and mitigation alternatives must be reviewed and approved by the LADWP. If the interconnecting utility determines that the only feasible mitigation includes transmission modifications or additions requiring CEQA review, the Energy Commission must analyze those modifications or additions according to CEQA requirements.

Scope of the LADWP system study

The LADWP performed an Interconnection System Impact Study (SIS) of the Beacon Solar Energy Project (BSEP), as requested by Florida Power & Light Company (FPL) Energy, LLC. The study included power flow, sensitivity, and short circuit studies, and transient and post-transient analyses (LADWP, 2008a, system impact study). The study modeled the proposed project for a net output of 250 MW. The base case system representation includes all the proposed upgrades in the LADWP area and any generator and transmission interconnection requests that are currently in LADWP's interconnection application queue ahead of the project. These conditions reflect the most critical expected loading condition for the transmission system in LADWP's area. In addition, the bulk power study evaluated conditions with dispatch of generation outside of the LAWDP service territory and electrical system in a manner that maximized loadings in the LADWP Main System area. The detailed study assumptions are described in the study. The power flow studies were conducted with and without BSEP connected to LADWP's grid at the Barren Ridge, using 2011 heavy summer peak and 2011 light autumn base cases. The power flow study assessed the project's impact on thermal loading of the transmission lines and equipment. Transient and post-transient studies were conducted for BSEP project using the 2011 heavy summer peak base case to determine whether the project would create instability in the system following certain selected outages. Short circuit studies were conducted to determine if BSEP would overstress existing substation facilities.

LADWP Power Flow Study Results

Heavy Summer Conditions:

Steady-state analysis of both primary and alternate point of interconnection cases reveals no thermal overload in the pre and post project system, except for the loss of both Rinaldi-Tarzana lines (N-2), which results in the overload of the Northridge-Tarzana line. However, this overload is resolved with partial load shed at Tarzana as an interim mitigation procedure. In addition, to address a long-term solution for this overload, LADWP is planning to upgrade the conductor of the impacted line with higher capacity.

Light Autumn Conditions:

No steady-state violations and no thermal overloads were found for all contingencies in the Pre and Post project system with either the primary point of interconnection or the alternate point of interconnection.

LADWP Transient Study Results

The Transient study was conducted for the critical single and double contingencies affecting the area listed in the page 8 of the LADWP SIS. The three-phase faults with normal clearing are studied for single contingencies; single -line-to-ground faults with delayed clearing are studied for double contingencies. All outage cases were evaluated with the assumption that existing Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) would operate as designed where required. Transient stability study indicates there would be no system performance issues caused by the BSEP project for primary point of interconnection.

LADWP Post-Transient Study Results

NERC/WECC planning standards require that the system maintain post-transient voltage stability when either critical path transfers or area loads increase by 5 percent for category ”B” contingencies, and 2.5 percent for category ”C” contingencies. Post-transient studies conducted for similar or larger generators in the area concluded that voltage remains stable under both N-1 and N-2 contingencies. All outage cases were evaluated with the assumption that existing SPS or RAS would operate as designed where required. The studies determined that the system remained stable under both single and double contingency outage conditions and the addition of the BSEP project for primary point of interconnection.

LADWP Short Circuit Study Results

Short circuit studies were performed to determine the degree to which the addition of BSEP project increases fault duties at LADWP’s substations, adjacent utility substations, and the other 230-kV, and 500-kV busses within the study area. The busses at which faults were simulated, the maximum three-phase and single-line-to-ground fault currents at these busses both with and without the project, and information on the breaker duties at each location are summarized in the Short Circuit Study Results tables (3 Phase to Ground and Single Line to Ground) of the System Impact Study Report (BSEP, 2008b, SIS, tables 3 to 10, Pages 16 to 19). The BSEP interconnection increases both three-phase and single-phase duties at several stations along the Inyo-Rinaldi line. These increased duties do not exceed the planned interrupting duty of 15KA of all Barren Ridge switching station circuit breakers. At the point of interconnection, two circuit breakers and four disconnect switches are required at the positions E31 and E32 of the Barren Ridge switching station. The continuous rating of the new circuit breakers and disconnect switches should be 3000A at the 230kV nominal voltage. The interruptible rating of the breakers should match with the existing level of 15kA.

The applicant should request a Facility Study to be performed by the LADWP to determine the cost estimates and work scope for interconnection facilities and the transmission network upgrades of the LADWP system.

COMPLIANCE WITH LORS

The study indicates that the project interconnection would comply with NERC/WECC planning standards and LADWP reliability criteria. The applicant will design, build, and operate the proposed 230-kV overhead single circuits.

Staff concludes that, assuming the proposed conditions of certification are met, the project would likely meet the requirements and standards of all applicable LORS.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

No agency or public comments related to the TSE discipline have been received.

CONCLUSIONS AND RECOMMENDATIONS

The proposed Beacon Solar Energy Project (BSEP) outlet lines and termination are acceptable and would comply with all applicable laws, ordinances, regulations, and standards (LORS). The analysis of project transmission lines and equipment, both from the power plant up to the point of interconnection with the existing transmission network as well as upgrades beyond the interconnection that are attributable to the project have been evaluated by staff.

- The modification of the existing Barren Ridge switch yard would occur within the fence line of the existing Los Angeles Department of Water and Power (LADWP) switchyard and would not trigger CEQA (California Environmental Quality Act).
- The applicant should request a Facility Study to be performed by the LADWP to determine the cost estimates and work scope for interconnection facilities and the transmission network upgrades of the LADWP system.

RECOMMENDATIONS

If the Energy Commission approves this project, staff recommends that the following conditions of certification be met to ensure both system reliability and conformance with LORS.

CONDITIONS OF CERTIFICATION FOR TSE

TSE-1 The project owner shall furnish to the Compliance Project Manager (CPM) and to the Chief Building Official (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.

Verification: At least 60 days prior to the start of construction (or a lesser number of days mutually agreed to by the project owner and the CBO), 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.

TRANSMISSION SYSTEM ENGINEERING 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 prior to the start of rough grading (or a lesser number of days mutually agreed to by the project owner and the CBO), 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.

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 (California Building Code, 1998, 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 or disapproval 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 plant 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:

1. Receipt or delay of major electrical equipment;

2. Testing or energization of major electrical equipment; and

3. The number of electrical drawings approved, submitted for approval, and still to be submitted.

Verification: At least 30 days prior to the start of each increment of construction (or a lesser number of days mutually agreed to by the project owner and the CBO), 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.

1. On both options, the BSEP project will be interconnected to the LADWP grid via 230kV, 795kcmil ACSR overhead conductors, single circuit generator tie lines. Under the alternate interconnection option, applicant has proposed to build a new 230kV, ring bus, three breaker switchyard to interconnect the project to the Barren Ridge switching station.

2. The power plant outlet line shall meet or exceed the electrical, mechanical, civil, and structural requirements of CPUC General Order 95 and General Order 98 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”, National Electric Code (NEC), and related industry standards.

3. Breakers and busses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.

4. 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.

5. The project conductors shall be sized to accommodate the full output from the project.

6. Termination facilities shall comply with applicable LADWP Utility interconnection standards.

7. The project owner shall provide to the CPM:

    a. The final Detailed Facility Study (DFS) including a description of facility upgrades, operational mitigation measures, and/or Special Protection System (SPS) sequencing and timing if applicable,

    b. Executed project owner and LADWP Facility 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:

1. Design drawings, specifications, and calculations conforming with CPUC General Order 95 and General Order 98 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 for the poles/towers, foundations, anchor bolts, conductors, grounding systems, and major switchyard equipment.

2. 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.

3. 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** 1) through 5) above.

4. The final Detailed Facility Study, including a description of facility upgrades, operational mitigation measures, and/or SPS sequencing and timing if applicable, shall be provided concurrently to the CPM.

TSE-6 The project owner shall provide the following Notice to the LADWP prior to synchronizing the facility with the LADWP transmission system:

1. At least one week prior to synchronizing the facility with the grid for testing, provide the LADWP 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 LADWP Outage Coordination Department.

Verification: The project owner shall provide copies of the LADWP letter to the CPM when it is sent to the LADWP one week prior to initial synchronization with the grid. A report of the conversation with the LADWP shall be provided electronically to the CPM one day before synchronizing the facility with the LADWP transmission system for the first time.

TSE-7 The project owner shall be responsible for the inspection of the transmission facilities during and after project construction, and any subsequent CPM and

[1] Worst-case conditions for the foundations would include for instance, a dead-end or angle pole.

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:

1. “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”; applicable interconnection standards; NEC; and related industry standards, and these conditions shall be provided concurrently.

2. 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.”

3. 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.

BSEP (Beacon Solar Energy Project). 2008a. Los Angeles Department of Water and Power (System Impact Study) submitted to the California Energy Commission.

BSEP (Beacon Solar Energy Project). 2007b. Beacon Solar, LLC, BSEP 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

ACSS Aluminum conductor steel-supported

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 – 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. It equals the product of the line voltage in kilovolts, current in amperes, and the square root of 3, divided by 1,000.

Megawatt (MW) – A unit of power equivalent to 1,341 horsepower.

Normal operation/normal overload – The condition arrived at when all customers receive the power they are entitled to, without interruption and at steady voltage, and with no element of the transmission system 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 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 – 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) – An automatic control provision, which, for instance, will trip a selected generating unit upon a circuit overload.

SF6 (sulfur hexafluoride) – An insulating medium.

Single contingency – Also known as “emergency” or “N-1 condition,” the occurrence 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 An integral part of a power plant and 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.

ALTERNATIVES

Eric K. Solorio

SUMMARY OF CONCLUSIONS

Staff has concluded that, as proposed, the Beacon Solar Energy Project (BSEP) will have significant adverse impacts to biological resources, cultural resources, soil and water resources, and visual resources. The project can avoid and or reduce these significant environmental impacts, and utilize water resources in a manner consistent with state policies by implementing any number of staff's proposed project alternatives, including utilizing non-potable water for cooling or incorporating alternative equipment and cooling technologies, and/or siting the project at an alternative location.

Staff concluded the “no project’ alternative is not a reasonable alternative to the proposed project, but there are seven feasible project alternatives that are reasonable alternatives to the proposed BSEP. Each of the seven alternatives is a reasonable alternative to the proposed BSEP because each alternative could reduce the BSEP's consumption of potable water by up to 97 percent. Five of the alternatives involve using a non-potable water source (brackish water) for wet cooling and power production. The sixth alternative would utilize the proven technology of dry cooling which does not require the use of water in the cooling process. The seventh alternative is utilizing photovoltaic technology (PV) which does not require a cooling system or the related water use.

Both PV and dry cooling have the added benefit of not only eliminating 97 percent of the water use but also eliminating the need for more than 40 acres of evaporation ponds; these ponds are a source of concern to the United States Fish and Wildlife Service and the California Department of Fish and Game. Utilizing either PV technology or dry cooling could also avoid the impacts to buried cultural resources by avoiding the mass grading activities required to excavate more than 40 acres of evaporation ponds. Although staff has determined that incorporating any of the seven project alternatives would avoid or greatly reduce some of the anticipated environmental impacts of the proposed project, staff has concluded that PV technology or dry cooling could avoid and reduce significant environmental impacts more than the five other project alternatives. Staff's conclusion is that all seven alternatives are reasonable alternatives to the proposed BSEP and economically feasible to incorporate, as described in detail in the **ALTERNATIVES** section, **ALTERNATIVES APPENDIX A**, and the **SOIL AND WATER RESOURCES** section.

INTRODUCTION

In this section staff evaluated potential alternatives to the construction and operation of the proposed Beacon Solar Energy Project (BSEP). Staff conducted the alternatives analysis in accordance with state environmental laws by providing an analysis of reasonable alternatives capable of reducing or avoiding any adverse impacts of the proposed project.

This Alternatives analysis and the Preliminary Staff Assessment, as a whole, are produced as part of the evidentiary record which is considered by the Commission when the Commission decides whether or not to approve the proposed BSEP or require modifications to the proposal. The decision making process takes into account various laws, ordinances, regulations, standards, state resource conservation policies, Commission policies, the *California Environmental Quality Act (CEQA), and the Warren-Alquist Act (Public Resources Code Section 25500 et seq.).*

DETERMINING THE SCOPE OF THE ALTERNATIVES ANALYSIS

The Guidelines for Implementation of the California Environmental Quality Act, Title 14, California Code of Regulations, section 15126.6(a) and(b), provides direction for scoping the alternatives analysis by requiring an evaluation of alternatives based upon 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”; “…even if these alternatives would impede to some degree the attainment of the project objectives, or would be more costly”. In addition, the analysis must address the “No Project” alternative (Cal. Code Regs., tit. 14, §15126.6[e]).

The range of alternatives required to be evaluated is governed by the “rule of reason” which requires consideration only of those alternatives necessary to permit a reasoned choice. Potentially feasible alternatives shall be selected and discussed to foster informed decision making and public participation. The *California Environmental Quality Act* (CEQA) guidelines state that an environmental document does not have to consider an alternative where the effect cannot be reasonably ascertained and whose implementation is remote and speculative (Cal. Code Regs., tit. 14, §15126.6[f][3]). To prepare the alternatives analysis, staff used the methodology summarized below:

- Identify the basic project objectives to use as screening criteria for project alternatives.
- Identify the proposed project’s significant adverse environmental impacts.
- Identify different types of alternatives to the project.
  - o Alternative project sites
  - o Alternative energy generation technologies.
  - o Alternative equipment and processes that can be incorporated into the proposed project.
  - o Consider the “No Project” alternative.
- Evaluate and determine whether any alternatives would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the environmental impacts of the proposed project.
- Summarize which alternatives, if any, can feasibly avoid or reduce the proposed project’s environmental impacts.

BASIC OBJECTIVES OF THE PROJECT

After reviewing the BSEP Application for Certification (08-AFC-2), staff has determined the four basic objectives of the Beacon Solar Energy Project (BSEP) to be as follows:

1. To construct, operate and maintain an efficient, economic, reliable, safe and environmentally sound solar-powered generating facility that will help achieve: (i) the State of California objectives mandated by SB 1078 (California Renewable Portfolio Standard Program), (ii) AB 32 (California Global Warming Solutions Act of 2006), and (iii) other local mandates adopted by the State's municipal electric utilities to meet the requirements for the long term, wholesale purchase of renewable electric energy for distribution to their customers.

2. To develop a site with an excellent solar resource.

3. To develop a previously disturbed site with close proximity to transmission infrastructure in order to minimize environmental impacts.

4. To interconnect directly to the Los Angeles Department of Water and Power (LADWP) electrical transmission system.

Staff eliminated applicant's fifth project objective as described on page 2-2, in the Application for Certification, "*To develop a site with available water resources to allow wet cooling in order to optimize power generation efficiency and reduce Project cost."* Staff eliminated this project objective as a screening criterion because the ground water at the project site is potable and therefore the objective to use potable water for power plant cooling, especially in a desert environment, is inconsistent with state policies, as generally described in the table below:

Alternatives Table 1
State Water Use Policies Affecting Power Plants

California Policies Regarding Water Use	Applicable Language
State Water Resources Control Board Resolution 75-58	State water policy regarding power plants is specified in Resolution 75-58 adopted by the State Water Resources Control Board (the Board). With respect to using fresh water, the Resolution articulates an underlying policy "**to protect beneficial uses of the state's water resources and to keep the consumptive use of freshwater for power plant cooling to that minimally essential for the welfare of the citizens of the state.**" The policy reflects the state's concerns over discharges from power plant cooling, as well as the conservation of fresh water for cooling purposes.
Integrated Energy Policy Report, Docket No: 02-IEP-1, p40	"**Water conservation is of paramount importance to the state**. Indeed, conserving fresh water and avoiding its wasteful use have long been part of the state's water policy, as reflected in the State Constitution, Article X, Section 2. **Because power plants have the potential to use substantial amounts of water for evaporative cooling, the Energy Commission has the responsibility to apply state water policy to minimize the use of fresh water, promote alternative cooling technologies**, and minimize or avoid degradation of the quality of the state's water resources."
Warren-Alquist, State Energy Resources Conservation and Development Act, California Public Resources Code 25008	"**It is further the policy of the state and the intent of the Legislature to promote all feasible means of…water conservation…**"

POTENTIAL SIGNIFICANT ENVIRONMENTAL IMPACTS OF THE PROJECT

In analyzing the Beacon Solar Energy Project (BSEP) staff identified potential significant adverse significant impacts to biological resources, cultural resources, soil and water resources, and visual resources. This analysis will evaluate the feasibility of incorporating potential alternatives that can avoid impacts to these resource areas.

If the BSEP is approved as currently proposed, staff estimates that construction and operation of the project would consume more than 60,000 acre feet of potable water, equating to more than 20 billion gallons of potable water, during the 30-year life of the project. The water would be pumped from on-site wells, drawing approximately 10,000 acre feet during construction and more than 1,600 acre feet per year for operations, from an aquifer already in overdraft condition. The aquifer has taken approximately 25 years to recharge half of the level of drawdown that resulted from prior intensive agriculture activities that ceased in the mid 1980s (BS 2008a, p. 1-10). The BSEP would significantly impact the groundwater resources by reducing the annual rate of groundwater recharge by approximately twenty percent (BS 2008a, p. 1-11). The BSEP does not propose to mitigate the project's impacts to potable, ground water resources in this desert environment. Please see the **SOIL AND WATER RESOURCES** section.

Impacts to biological resources, from the proposed BSEP project would result from mass grading more than 5 million cubic yards of soil covering more than 2,000 acres. The grading activities include removal of approximately 430 acres of vegetation that provides cover, foraging, and breeding habitat for wildlife. Impacts to biological resources also include the loss of approximately 60 acres of desert wash scrub habitat and 16.0 acres of jurisdictional waters of the state. Additionally, the construction of more than 40 acres of evaporation ponds could have a significant adverse impact on migratory birds, water fowl and wildlife as well as potentially increase predation of protected species. Please see the **BIOLOGICAL RESOURCES** section.

Staff also concluded that because there are known cultural resources on site, the mass grading of more than 5 million cubic yards of soil would have significant direct impacts on surface and subsurface prehistoric archaeological resources. Please see the **CULTURAL RESOURCES** section.

The introduction of the project would change the existing physical setting of the Fremont Valley floor from a moderately disturbed desert floor landscape to a highly human-altered landscape. This change principally would be due to 1,244 acres of the project site being covered with parabolic trough solar collectors. In addition, the introduction of the radiance from the parabolic trough arrays during operation would be prominent from elevated locations. Staff concluded the project would cause significant adverse impacts at two key observation points that would be unmitigable. Please see the **VISUAL RESOURCES** section.

IDENTIFY, SCREEN AND EVALUATE PROJECT ALTERNATIVES

The range of project alternatives considered in this analysis includes three alternative sites, six alternative generation technologies, and one alternative site configuration. The analysis also considers six alternative selections of equipment, five of which would use a non-potable (brackish) water source.

ALTERNATIVE TO IMPACTING WATERS OF THE STATE

In their June 19, 2008 comment letter on BSEP, the CDFG recommended avoiding impacts to state waters and requested that the applicant evaluate alternative site layouts that would avoid the desert washes (DFG 2008b). The applicant’s response (CEC 2008uu) indicated that avoiding the washes would be infeasible because the plant site does not offer sufficient space to locate the project entirely on one side of the wash or the other, requiring splitting the project into two uneven portions that would straddle the wash. Locating a single project on this site with Pine Tree Creek (dry wash) bisecting the middle would require multiple crossings of the wash for roads and pipes (heat transfer fluid and natural gas), resulting in major disruption of the wash during construction and significantly changing the nature of the wash. The applicant also pointed out that the layout would shift the power block significantly off-center of the field, resulting in operational problems, longer plant start-ups, lower annual energy production, and overall higher cost of electricity.

Staff believes the applicant need not locate the entire project on one side of the desert wash nor straddle the wash with the entire project utilizing one 250 megawatt (MW) power block. Instead applicant could avoid Pine Tree Creek entirely by constructing two half scale facilities: a 125 MW plant on each side of the desert wash (still achieving the desired 250 MW). Such a modification to the layout could provide increased efficiencies in land use while avoiding impacts to state waters. The efficiencies could be gained by avoiding the substantial excavation costs of filling the existing 2-mile long channel and constructing a new longer diversion channel. Further cost savings could be realized by avoiding the requirement to provide mitigation lands, endowment funds and a management plan.

ALTERNATIVE PROJECT SITES

The applicant provided a general discussion (BS 2008a, pp. 4.5-7) of alternative ***areas*** to site the proposed project without necessarily identifying a particular alternative project ***site*** that was available for development. Although the proposed BSEP site is previously disturbed and in close proximity to transmission lines, the proposed site is bisected by designated waters of the state (Pine Tree Creek) which applicant proposes to relocate one-half mile to the east. There may be alternative sites that have also been previously disturbed by agriculture activities and yet do not have any waters of the state on site. If this is the case then such alternative disturbed sites could otherwise avoid impacts to several environmental resource areas. As a result, staff intends to identify and evaluate specific project sites prior to publishing staff's Final Staff Assessment.

For the purpose of this Preliminary Staff Assessment, staff is working under the assumption that the alternative areas identified by applicant contain sites that are available for acquisition, and that staff will later identify specific potential project locations, within said areas.

Antelope Area

As shown on **Alternatives Figure 1**, the Antelope area has reasonable access to infrastructure. There appears to be many potential project sites surrounding the Cottonwood substation and also the Neenach substation. These areas have not yet been identified as habitat for special-status specie. The area also appears to be absent of any designated waters of the state and/or waters of the US. Because the BSEP proposed site contains designated waters of the state that bisect the project site, and the proposed BSEP would also have impacts to special-status species, the Antelope area should be considered further to determine whether impacts to special-status species and impacts to waters of the state can be reduced or avoided.

Manix Area

As shown on **Alternatives Figure 2**, the Manix area has reasonable access to infrastructure. The Manix area appears to contain potential project sites. This area has not yet been identified as habitat for special-status specie. However, the area also appears to contain designated waters of the state and/or waters of the US. There is no data in the AFC that identified the quality of water resources in the area. If the area contains non-potable water sources then it could potentially lessen the impacts of the BSEP on soil and water resources. Because this area does not appear to be designated habitat for special-status species and potentially has non-potable water resources, staff will identify specific sites in the Manix area and determine whether impacts to those resource areas can be reduced or avoided. Staff's conclusions will be included in the Final Staff Assessment.

South Edwards Area

As shown on **Alternatives Figure 3**, the South Edwards area appears to contain potential project sites with reasonable access to infrastructure. The “alternative siting study area” appears to contain designated prime farmland and limited habitat for special-status species, although the southeast portion of the study area appears to contain potential project sites unaffected by these constraints. There is no data in the AFC that identified the quality of water resources in the area. If the area contains non-potable water sources then it could potentially lessen the impacts of the BSEP on soil and water resources. Because this area has potential project sites that are not designated habitat for special-status species and potentially has non-potable water resources, staff will identify specific sites in the South Edwards area and determine whether impacts to those resource areas can be reduced or avoided. Staff’s conclusions will be included in the Final Staff Assessment.

ALTERNATIVE ELECTRICITY GENERATION TECHNOLOGIES

The second component of the Alternatives Analysis is to consider project alternatives to the proposed electricity generation technology. Alternative technologies considered for the project included the following fuel sources: oil, natural gas, coal, nuclear, water, biomass, municipal solid waste, and solar. Each technology is discussed below, in regards to its potential application in the proposed project.

Four non-solar renewable technological alternatives (geothermal, biomass, tidal, and wave technologies) were eliminated from further consideration do to their impacts on air quality, biological resources, and soil and water resources. Also, wind technology that could be viable at some locations in the Mojave Desert was eliminated from further consideration due to greater impacts on biological resources.

Of the nonrenewable generation alternatives (natural gas, coal, and nuclear), only the natural gas-fired power plants would be viable alternatives within California. However, staff determined that none of the alternatives described above would “substantially lessen any of the significant effects of the project [and] feasibly attain most of the basic objectives of the project”, California Code of Regulations, Title 14 § 15126.6(f).

Conventional Combined-cycle, Kalina combined-cycle, and Advanced Combustion Turbine Cycle

Conventional combined-cycle, Kalina combined-cycle, and Advanced Combustion Turbine Cycle are all combined-cycle technologies that convert natural gas fuel into electricity using the combustion process, and also convert the excess heat (resulting from the combustion process) into electricity. All of these technologies would have more significant impacts on air quality than the proposed BSEP. Additionally, aside from the air emissions from combusting the natural gas, the Kalina combined-cycle technology utilizes a media consisting of water and ammonia in the boiler process. These alternatives also fail to meet the project objective of helping to achieve: (i) the State of California objectives mandated by SB 1078 (California Renewable Portfolio Standard Program) and (ii) AB 32 (California Global Warming Solutions Act of 2006). Using natural gas-fired turbines as an alternative power generation technology would create greater impacts to air quality and fail to meet the primary project objective, and was therefore ruled out as a project alternative to the proposed BSEP.

Fuel Cells

Various types of fuel cell technologies such as those that use hydrogen and oxygen are available but have not been proven to work on a commercial scale such as the 250 MW application proposed in the BSEP. Using fuel cells as an alternative power generation technology was therefore ruled out as a project alternative.

Hydroelectric

Hydroelectric technology is commercially available. However, constructing and operating a new dam and hydroelectric plant is not technically or logistically feasible due to the lack of an adequate water source in the region. More so a hydroelectric application would cause greater environmental impacts on any available water source, as compared with the proposed BSEP. The capital cost differential is also prohibitive and therefore for the reasons stated above, hydroelectric technology was eliminated as an alternative power generation technology.

Geothermal

Constructing and operating a new geothermal plant would have a more significant impact on ground water resources. Relative to the proposed project, geothermal facilities have greater impacts on soil destabilization and seismic activity. Moreover, there are not any known available geothermal resources in the project vicinity. In comparison to the proposed project, geothermal technology is not feasible logistically, is cost prohibitive and would have increased environmental impacts, as compared to the BSEP. As such, geothermal technology was eliminated as an alternative power generation technology.

Wind Generation

Wind driven electricity generators have some of the lowest environmental impacts on air and water resources, in particular. However, wind technology can have significant impacts on wildlife, in particular windmills "…*kill birds by the hundreds that fly into them*" (SB 2009a). Windmills also have a similar effect on bats which are an important part of the ecosystem. Although wind technology is commercially viable, it can be difficult to finance due to the inherent risk arising from its unreliability. The unreliability is due to the intermittent nature of when the wind blows and the limited locations that are conducive to the volumes of wind needed for economically viable power generation. Due to the greater level of impacts on biological resources, as compared with the proposed BSEP, wind technology was eliminated as an alternative power generation technology.

Photovoltaic

Photovoltaic technologies (PV) are considered the primary competitor with solar thermal technologies because both applications require similar amounts of land resources to convert solar energy into electricity. The reliability of PV technology is equivalent to that of solar thermal technology due to the same dependence on solar incidence necessary to allow the collection of solar radiation. In considering PV technology as an alternative to the BSEP, staff finds significant cost advantages and environmental advantages of utilizing PV applications compared to solar trough thermal technology.

Although both PV applications and the proposed BSEP would have similar impacts to land resources and vegetation that provides cover, foraging and breeding habitat for wildlife, staff concludes PV could avoid substantial impacts to water resources, biological resources and cultural resources that could otherwise result from the proposed BSEP. These impacts can be avoided because PV applications do not require power plant cooling systems, such as the proposed BSEP. The proposed BSEP would require more than 1,600 acre feet of water annually of which the majority would be used in a wet cooling system. The only water consumption that PV applications require would be for biannual washing of the PV panels which is far less than the need to regularly wash the solar troughs proposed by the BSEP (BCV 2009a and BS 2008a, Figure 2-13). Additionally because PV applications do not require cooling systems, there is not a need for evaporation ponds to discharge spent cooling water to, as reflected in the BSEP proposal. Because PV applications can avoid using evaporation ponds, the use of PV technology can also avoid significant impacts to cultural and biological resources associated with these ponds, see **Biological Resources** and **Cultural Resources** sections.

Economic Feasibility of Photovoltaic (PV) Technology on a "Cost per Watt" Basis

Due to the increasing market demand for solar technology applications, there has been substantial progress in reducing the cost per watt of PV technologies, to the point where PV technology is affordable, scalable and has a low environmental impact on a life-cycle basis. There are two cost components that make PV technology cost competitive with solar thermal technology. The first component is the installed cost per watt. Staff identified a utility scale PV project being developed by Sempra Generation, a subsidiary of San Diego-based Sempra Energy. The project is a 10 MW plant recently constructed in Boulder City, Nevada. According to Michael Allman, President of Sempra Generation, PV technology is more cost effective than solar thermal trough technology. Mr. Allman states "*We looked at both concentrated solar power and photovoltaic and it was our belief that photovoltaic was the least expensive electricity to develop from solar power.*" (BCV 2009a). Staff also contacted the company Applied Material, an international manufacturer of equipment that manufactures thin film PV solar panels (CEC 2009j). Steve Stokowski, Solar Sales Manager of Applied Materials, estimated the installed cost of thin film PV technology at approximately $3.90 per watt. This cost appears to be equivalent to the BSEP project cost (BS 2008a). Based on these two market reference points, staff concludes that the cost of PV technology is equivalent to the installed cost per watt of solar trough thermal technology, as proposed by BSEP.

The second cost advantage of PV is the significantly reduced operating costs. Solar thermal electricity generating facilities have far greater staffing requirements than PV electricity generating facilities. The proposed BSEP facility would require 66 full time workers to operate and maintain the facility compared with a PV facility that can operate with just a single person (BS 2008a, BCV 2009a, and CEC 2009i). The lower operating costs of PV applications results in more free cash available for debt servicing, which is a key determinate (debt service coverage ratio) for lenders when considering project financing. Staff finds there are cost advantages from utilizing PV technology, in place of solar thermal technology as proposed by BSEP.

Because PV technologies have a less than or equivalent cost per watt to develop, as compared with solar thermal technologies, and PV technologies have much lower operating costs, staff concludes that PV technology is an economically feasible alternative to solar thermal technology.

Market Based Approach to Economic Feasibility of Photovoltaic (PV) Technology

Staff next applied a market based approach to determine if the broader market of energy generators (developers) considered PV technology to be cost competitive with solar thermal technology. Staff researched the US Department of Interior, Bureau of Land Management (BLM) website at http://www.blm.gov/ca/st/en/prog/energy/solar.html and found a list (BLM Applications Table) of utility scale PV projects proposed to be developed by the private sector (BLM 2009a). The scope of these PV projects can be described as 23 projects covering more than 150,000 acres with capacity to produce more than 14,500 megawatts of electricity.

In addition to the projects proposed to be developed on BLM lands, staff researched PV projects at the Solar Energy Industries Association at http://www.seia.org. Staff found that the parent company of BSEP, Florida Power & Light (FPL) has several PV projects under development in Florida (SEIA 2009a). Considering the breadth of proposed PV projects on BLM lands, and applicant's PV projects in Florida, the overall market (and applicant) has determined that PV technology is economically viable and competitive with solar thermal technology.

Staff finds the generating of 250 MW of electricity using PV technology has cost advantages, financing advantages, reduces potable water consumption by up to 97 percent, and avoids significant impacts to cultural and biological resources by avoiding need for 40 acres of evaporation ponds. Staff finds PV technology to be economically feasible and a reasonable alternative to the proposed BSEP.

ALTERNATIVE EQUIPMENT AND PROCESSES

The project proponent, Beacon Solar LLC, a subsidiary of FPL Energy LLC (FPLE), has proposed a wet cooling system using *potable* water, on the basis that FPL believes using non-potable water or dry cooling technology would "…create a significant cost disadvantage..." and rejects these reasonable alternatives as being "…economically unsound" (BS 2008a, pp. 1-4, 4-15). Currently, the proposed BSEP is the only solar thermal project engaged in the Energy Commission's licensing process that has proposed to use potable water for wet cooling.

Appendix A describes six alternative equipment and process configurations, five of which would use a source of non-potable (brackish) water. All six alternatives would avoid or reduce the proposed BSEP's impacts on the various environmental resource areas. Staff therefore focuses this discussion on the economic feasibility of being able to incorporate any one of the six alternatives described in Appendix A.

Utilizing Non-Potable Water or Dry Cooling as Project Alternatives

Staff conducted an independent analysis to evaluate the economic feasibility of using non-potable water in various wet cooling systems or in the alternative utilize dry cooling technology for the proposed BSEP, see **Appendix A** and **SOILS & WATER**

RESOURCES section. Staff has determined there is non-potable (brackish) water available in the Koehn Lake area. This source is approximately five miles from the project site and can be accessed by installing an underground pipeline in the road right-of-way along Neuralia Road and Munsey Road.

Profit Based Approach to Economic Feasibility of Cooling System Alternatives

Staff's approach to evaluate the economic feasibility of each alternative listed in Appendix A began with first identifying industry benchmarks for the expected rate of return on investment, also known as the internal rate of return (IRR). Staff first considered the company eSolar, a developer of large scale solar thermal power plants, as a reference point. eSolar was considered a solid market reference point because they have entered into power purchase agreements to sell their electricity in New Mexico and California. The company has signed a 20-year contract to provide Southern California Edison (SCE) the energy from a 245 megawatt solar thermal power plant. That project is nearly identical in size to the proposed 250 megawatt BSEP. According to Bill Gross, Chief Executive of eSolar, internal rates of return will fall within the range of 11 percent to 14 percent (GW 2009 A). Considering that eSolar is developing projects of smaller scale and larger scale than the proposed BSEP, economic feasibility for solar thermal plants appears to be reasonably determined by achieving an IRR of 11 percent or more.

The next step in staff's analysis was to establish BSEP's internal rate of return (IRR) under different scenarios that accounted for the cost of each alternative. Staff therefore requested the baseline project cost data and revenue data from the BSEP proponent. The data was submitted to staff under an application for confidentiality which was granted by the Commission's Executive Director (DB 2009l). Staff then generated a feasibility study with cost estimates for five separate reasonable alternatives that each would utilize non-potable water from Koehn Lake and various alternative equipment selections to treat, recycle and conserve the water in the power generation process. The feasibility study also included the additional alternative of dry cooling, see "ACC 40F ITD", **APPENDIX A**.

In comparing the marginal cost of the various alternatives to the anticipated revenue stream of the BSEP, staff concluded that all six of the a reasonable alternative would be economically feasible under the benchmark staff established as achieving an internal rate of return (IRR) of 11 percent or more. Staff reached this conclusion by estimating equipment costs, debt service, and annual operating costs then applied those costs to the revenue model which yielded results that met or exceeded 11 percent IRR over 30 years.

Several additional considerations that improve the profitability of incorporating any of the alternatives identified in **APPENDIX A** are as follows. Applicant has recently advised staff that the proposed BSEP is eligible to obtain grant funding. Applicant stated "*More recently, at the federal level, legislation has been enacted as part of the <u>President's stimulus package to encourage the construction of renewable energy facilities by **providing for grants** to any qualifying project that begins construction in 2009 or 2010</u>. (See H.R. 1, § 1603, 111th Cong. (2009) (enacted).)*" (DB 2009m). The stimulus package also provides loan guarantees for renewable projects. The available grants could potentially offset the entire cost (or more) of any of the alternatives described in

Appendix A. Further, staff did not take into account the 30 percent tax credit that applicant would receive for the increased cost to purchase and install any of the equipment. These added benefits would increase applicant's bottom line profits – internal rate of return.

It is also worth noting that a "residual value" of the BSEP was missing from the BSEP revenue model which would yield an IRR that is more than staff's estimate, therefore staff's estimate is conservative. The residual value component would reflect what the power plant was worth at the end of the 30 years. Because the revenue model assumes a cost for annual maintenance, the power plant would be fully maintained and operating at the end of 30 years (revenue model) and long after the debt financing was repaid. Therefore it could be sold for a lump sum or held for its continuing cash flow. The residual value is a significant factor that should have been included in the revenue model when establishing the complete project cash flow (DB 2009l). It follows that staff's estimate of value is understated and the project would likely reach an IRR above staff's estimate.

Market Based Approach to Economic Feasibility

Staff then took a broader approach to establish economic feasibility based upon the overall market. This market is defined by solar thermal projects with capacity of 50 megawatts or more, constructed within the last 10 years in California or proposed to be built in California. The table below provides a brief description of solar thermal projects being considered for certification by the Energy Commission. Each project proposes to use a cooling system that avoids impacts to fresh water resources.

Alternatives Table 2
Solar Thermal Projects with Cooling Systems Consistent with State Policy

Project	Capacity	Generation Technology	Cooling System
Carrizo Energy Solar Farm (07-AFC-8)	177 MW	Compact Linear Fresnel Reflector solar thermal technology	Dry cooling (air-cooled condenser)
Ivanpah Solar Electric Generating System	400 MW	Power tower solar thermal technology	Dry cooling (air-cooled condenser)
San Joaquin Solar 1&2 Hybrid Project (08-AFC-12)	106 MW	Solar parabolic trough/biomass	Wet cooling using reclaimed water
Palmdale Hybrid Power Project (08-AFC-9)	570 MW	Solar parabolic trough and natural gas-fired combined cycle	Wet cooling using reclaimed water
Victorville 2 Hybrid Power Project (07-AFC-1) **APPROVED**	563 MW	Solar parabolic trough and natural gas-fired combined cycle	Wet cooling using reclaimed water

Staff also considered the company BrightSource Energy ("BrightSource"), as a market referent. BrightSource was considered for several reasons: 1.) they currently propose to develop the Ivanpah Solar Electric Generation System ("Ivanpah") which is a solar thermal project in a similar desert environment and will use dry cooling, 2.) they have entered into the world's largest power purchase agreement to sell Southern California

Edison 1,300 megawatts of electricity from BrightSource's solar thermal projects (GW 2009 B), and 3.) the Ivanpah project consists of three power plants, two of which are 100 megawatts each and one that is 200 megawatts. These three plants are each smaller than the proposed BSEP project and therefore demonstrate the economic feasibility of dry cooling, on a scale smaller than the proposed BSEP.

BrightSource has demonstrated by its development proposals to supply SCE with 1,300 megawatts (produced from solar thermal plants that utilize dry cooling) that dry cooling is economically feasible (CEC 2009k). BrightSource also acknowledges that the efficiency loss of using dry cooling in place of wet cooling is "marginal" and therefore does not render a project infeasible (CEM 2009 A). More so, the proposed BSEP appears to be twice as efficient, on a megawatt per acre basis, than Ivanpah, see **Efficiency Table 1** in the **EFFICIENCY** section of this PSA.

Considering the facts above, staff finds the overall marketplace has established the economic feasibility of both: using dry cooling technology or the lesser expensive alternative of reclaimed water in wet cooling systems. The economic feasibility is further demonstrated by the use of these cooling technologies in both smaller and larger scale power plants, as compared to the proposed BSEP.

THE "NO PROJECT" ALTERNATIVE

CEQA Guidelines and Energy Commission regulations require consideration of the "No Project" alternative. The CEQA Guidelines state that "the purpose of describing and analyzing a No Project Alternative is to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project" (Cal. Code Regs., tit. 14 §15126.6[i]). Toward that end, the "No Project" analysis considers "existing conditions" and "what would be reasonably expected to occur in the foreseeable future if the project were not approved…" (§15126.6[e][2]).

In short, the site-specific and direct impacts associated with the power plant would not occur at this site if the project does not go forward. Selection of the "No Project" alternative would render all concerns about project impact moot. The "No Project" alternative would preclude any construction or operation and, thus, grading of the site or installation of new foundations, piping, or utility connections.

If the project were not built, off-takers of the renewable energy from BSEP would not benefit from the annual, solar power this project would provide. A primary benefit of the BSEP is that it would help achieve: the State of California objectives mandated by SB 1078 (California Renewable Portfolio Standard Program), and AB 32 (California Global Warming Solutions Act of 2006).

If the proposed project was not constructed then during peak demand periods, potential off-takers of the solar power may have to rely on existing, inefficient, older power plants which are known to consume more fuel and emit more air pollutants per kilowatt-hour generated than the proposed BSEP.

In light of the California Renewable Portfolio Standard Program and the California Global Warming Solutions Act of 2006, in the absence of the proposed Beacon Solar

Energy Project, other power plants with unknown technologies would likely be constructed in the region to supply the market demand for energy. As such, staff has concluded the "No Project" alternative would not be a reasonable alternative or a feasible alternative to the proposed project.

CONCLUSIONS

ALTERNATIVE SITES

After evaluating the alternative project siting areas proposed by applicant, staff concludes there may be a reasonable alternative site. Staff will conduct further analysis to make that determination and incorporate the conclusions into the Final Staff Assessment (FSA).

ALTERNATIVE ELECTRICAL GENERATION TECHNOLOGIES

After evaluating the various alternative electrical generation technologies and applying the screening criteria, staff has determined many of the alternative technologies evaluated are not viable technologies for the proposed BSEP. However, photovoltaic technology (PV) is a feasible alternative generation technology for the proposed BSEP because such an application reduces potable water consumption by up to 97 percent and avoids significant impacts to cultural and biological resources by avoiding need for 40 acres of evaporation ponds. Staff concludes that incorporating the reasonable alternative of PV technology (or in the alternative a dry cooling system) would significantly avoid certain environmental impacts of the proposed BSEP.

ALTERNATIVE EQUIPMENT AND PROCESSES

Staff has determined that all six alternative cooling options, described in Appendix A, are economically feasible to incorporate into the proposed BSEP. Staff has reached this conclusion because although each of the six alternatives would have an economic cost to implement, the cost would not impact BSEP revenues to a point where revenues would fall below the industry benchmark - yielding an annual return on investment of 11 percent or more. Moreover, staff found all six of the alternatives to be economically feasible because they "…would feasibly attain most of the basic objectives of the project [and] would avoid or substantially lessen any of the significant effects of the project…**even if these alternatives would…be more costly**", Title 14, California Code of Regulations, section 15126.6(a)(b).

Although staff has determined that incorporating any of the six reasonable, project alternatives, described in Appendix A, would avoid or reduce some of the anticipated significant environmental impacts of the proposed BSEP, staff concludes that dry cooling is the preferred project alternative because it avoids and reduces more environmental impacts than the other five project alternatives, and dry cooling is economically feasible.

APPENDIX A
FEASIBILITY STUDY OF WATER SUPPLIES AND COOLING SYSTEMS

Michael N. DiFilippo

WATER SUPPLY & COOLING

The Beacon Solar Energy Project (BSEP) would utilize onsite groundwater for all plant needs including cooling and steam generator feedwater as well as potable uses. Cooling will be provided by a mechanical draft cooling tower. Plant wastewater (from all sources) would be sent to evaporation ponds for final disposal. No backup cooling water supply is planned for by the applicant although they offer to use future tertiary treated effluent from California City if it becomes available.

Staff has compared the environmental and economic merits of the proposed project with an alternate water supply and one cooling alternative as follows:

PROPOSED PROJECT

All BSEP water needs (including potable needs) will be met by groundwater pumped from wells on the plant site. There are 12 existing water supply wells that were previously used for farming at the site - four wells would be used to supply water for the project (two operating and two backup). The applicant projects water use as follows:

Water Use

Water Use	Annualized Average Rate[1], gpm	Peak Rate[2], gpm	Estimated Annual Use, Acre Feet
Plant Operation	990	4,054	1,599
Potable Water	5	5	8

1. The estimated groundwater usage in gallons per minute is based on an average daily consumption.
2. The peak rate is the instantaneous maximum for summer usage.

Water uses would include cooling tower makeup, closed cooling system makeup, steam generator makeup, mirror washing, plant wash down (housekeeping and maintenance), dilution water for chemical feed systems, etc. Well water would also be used for potable uses - drinking, showers, sinks, and toilets. Well water would be stored on site in the Raw Water Tank. Most of the water would be treated using ion exchange (SAC-SBA) and stored in the Process Water Tank. Process water would be used for cooling tower makeup. A portion of the process water would be treated further for steam generator makeup and mirror washing utilizing portable demineralizers (these are regenerated offsite and generate no wastewater). Wastewater sources include cooling tower blowdown, steam generator blowdown, plant drains, water treatment waste streams, etc. Cooling tower blowdown and SAC-SBA neutralized wastewater would be sent to three 8.3 acre evaporation ponds. Steam generator blowdown and plant drains would be recycled to the cooling tower. The applicant claims that the ponds are sized to accommodate all solids residue generated throughout the life of the plant.

The treatment process selected by BSEP was driven by the PM10 requirements placed on the cooling tower (by the AQMD). The total dissolved solids (TDS) of the circulating water must be less than 1,600 mg/l to meet the PM10 limit. Also, BSEP plans to operate the cooling tower at 15 cycles of concentration (the ratio of feedwater flow to blowdown flow is 15) to minimize wastewater generation. This also means that the TDS of the makeup water (onsite wells) must be reduced to approximately 100 mg/l. BSEP proposes using SAC-SBA ion exchangers to accomplish this. SAC-SBA vessels contain ion exchange resin specifically designed to remove cations (positive ions) and anions (negative ions) from water. The SAC and SBA vessels have a fixed capacity to remove ions, and therefore, must be removed from service frequently and regenerated. This is accomplished by passing dilute sulfuric acid through the SAC vessel (strong acid cation) and dilute sodium hydroxide through the SBA vessel (strong base anion). Wastewater which can have very high or low pH would require neutralization prior to disposal.

In the applicant's water balance for typical annual conditions, they show a wastewater rate to the evaporation ponds of 471 gpm (Section 2, Figure 2-13). This consists primarily of cooling tower blowdown and wastewater from water treatment. They plan to operate at an annual 26.5 percent capacity factor (94% capacity factor during daylight periods). Adjusting wastewater flow to a 24-hour operating basis, flow to the evaporation ponds would be 125 gpm (471 gpm x 26.5%). All ponds would have to operate for the entire year to accommodate this flow. Stated another way, the evaporation rate from the ponds would have to be 97 inches per year. Evaporation pan data for this area is about 120 inches per year. Pan data is measure of ambient evaporation rate and is measured with a National Weather Service Class A pan (measuring 48" diameter x 10" deep). Past experience in sizing evaporation ponds (by author) was to adjust the Class A pan data by 40 percent to 45 percent for salinity and edge effects. This equates to an adjusted evaporation rate of approximately 66 to 72 inches. As ponds concentrate, high levels of salt inhibit evaporation. Additionally, the size, shape and depth of the pond also reduce evaporation. The ponds as sized are marginal and a fourth pond would likely be required. Also, if water use in the plant is greater than that described in the water balance (Figure 2), additional pond area would be required.

ALTERNATIVE WATER SUPPLY (BRACKISH WATER) AND TREATMENT PROCESSES

As a means of conserving high quality (potable) onsite groundwater, five treatment alternatives were evaluated utilizing offsite brackish water. Refer to the following table. All the alternatives would utilize well water from a brackish makeup source. The water is considered brackish because State Water Resources Control Board, Resolution 75-58 defines brackish waters as "all waters with a salinity range of 1,000 to 30,000 mg/l" and the water at Koehn Lake fits within those parameters. The aquifer is accessible at the southwest corner of Koehn Lake approximately 5 miles from the project site. It was assumed that four wells would be required to supply BSEP needs. In all of the alternatives well water would be transported to the site via a 12-inch or 14-inch pipeline (depending on water demand).

Offsite Brackish Water Alternatives					
	SAC-SBA	Makeup RO	Recovery RO	Evap/Crys	Evap Ponds
Alternative 1	X				X
Alternative 2	X		X		X
Alternative 3		X	X		X
Alternative 4	X			X	
Alternative 5		X	X	X	

All of the processes in the above table are well established commercial technologies.

SAC-SBA in Alternative 1 is the same ion exchange process proposed by BSEP.

Reverse osmosis (RO) would be used in two ways – as makeup treatment or in a wastewater recovery configuration. In alternatives 2 and 5, RO would be used to directly treat cooling tower makeup, steam generator makeup and mirror washing water. In Alternatives 2, 3 and 5, RO would be used to treat cooling tower blowdown to reduce overall wastewater volume either for disposal or as a pretreatment to an evaporator. RO is a technology that utilizes permeable membranes (under relatively high pressure) to repel salt and pass water. Most of the dissolved salts are repelled by the membrane surface (95% to 98% for most ions) allowing only water to pass through. RO must have highly filtered water with modified chemistry (usually pH adjustment) to operate successfully. In the alternatives utilizing RO, the water would be filtered by the use of microfiltration (MF). MF is also a membrane process that is commonly used with RO in difficult industrial or reuse applications.

Evaporator/Crystallizers in Alternatives 4 and 5 would be used to reduce wastewater volume to essentially zero volume. In the evaporator 90 percent to 95 percent of the water would be recovered. Brine from the evaporator would be sent to a crystallizer to further recover water. Waste from the crystallizer would be in the form of highly concentrated salt brines that would crystallize to solid form for offsite disposal. In Alternative 5, a recovery RO would be used to pre-concentrate the wastewater stream to the evaporator. Alternatives 4 and 5 would be the only treatment options requiring offsite disposal.

COMPARATIVE WATER CONSUMTION OF VARIOUS PROCESSES

Refer to the following table for a comparative summary of onsite water versus offsite brackish water for BSEP makeup. The analysis was based on typical summer conditions. Note the evaporation pond sizing for the BSEP proposed treatment. Staff calculated a pond size (utilizing the criteria discussed above) of 43.5 acres versus 25 acres in the BSEP project description.

Water Treatment Summary						
Typical Summer Conditions Basis						
		Offsite Wells - Koehn Lake Source Water				
	BSEP Onsite Wells SAC-SBA	Alternative 1 SAC-SBA	Alternative 2 SAC-SBA Recov RO	Alternative 3 MU RO Recov RO	Alternative 4 SAC-SBA Evap-Crys	Alternative 5 MU-Recov RO Evap-Crys
Water Demand - Instantaneous						
Onsite Wells Demand, gpm	4,038	5	5	5	5	5
Koehn Lake Water Demand, gpm	N/A	4,086	3,772	3,959	3,463	3,480
Total Wastewater, gpm	572	650	565	801	0	0
Water Demand - Annual Average Conditions						
Annual Capacity Factor	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
Onsite Wells Demand, gpm	1,070	5	5	5	5	5
Koehn Lake Water Demand, gpm	N/A	1,083	1,000	1,049	918	922
Onsite Wells Demand, AF/yr	1,726	8.1	8.1	8.1	8.1	8.1
Koehn Lake Water Demand, AF/yr	N/A	1,747	1,612	1,692	1,480	1,488
Total Wastewater, gpm	152	172	150	212	0	0
Evap Pond, acres[1]	43.5	49.4	42.9	60.8	0	0

Notes.....

1. BSEP project evap pond was sized based based on staff calculation.

The offsite well field at Koehn Lake would be the same for all of the alternatives (1 through 5). Each well was assumed to be 500 feet deep. The pipeline diameter for Alternatives 1 and 3 is 14 inches and 12 inches for Alternatives 2, 4 and 5. The size differences are a function of water demand for each alternative. For this analysis, the line was sized to operate 24 hours per day at half the water demand rate.

ALTERNATIVE 1

Alternative 1 utilizes “brackish” water from offsite wells for plant needs, e.g. cooling tower makeup, closed cooling system makeup, steam generator makeup, mirror washing, etc. Steam generator blowdown and plant drains would be recycled to the cooling tower. It is the same alternative proposed by BSEP. Well water from onsite wells would still be used for potable needs. Plant wastewater would be sent to an evaporation pond for final disposal. The evaporation ponds would be about 15 percent larger than the BSEP ponds because more wastewater would be generated by the SAC-SBA treating brackish water.

ALTERNATIVE 2

This alternative combines Alternative 1 (SAC-SBA) with a recovery RO to reduce the cooling tower blowdown portion of the wastewater stream. MF would be used as pretreatment for the recovery RO. The evaporation ponds would be slightly smaller than the BSEP ponds.

ALTERNATIVE 3

In this alternative offsite water would be treated with and RO prior to storage in the Process Water Tank (replacing SAC-SBA). A portion of cooling tower blowdown would also be recovered via RO prior to discharge to evaporation ponds. MF would be used as pretreatment for the makeup and recovery RO. Steam generator blowdown and plant drains would be recycled to the cooling tower. RO permeate would be recovered to the cooling tower. This alternative would generate more wastewater than Alternatives 1 or 2 and would require a significantly larger evaporation pond.

ALTERNATIVE 4

This alternative combines Alternative 1 (SAC-SBA) with an evaporator/crystallizer and would essentially eliminate a liquid waste stream. There would be no evaporation pond in this alternative. Crystallizer solid waste would require offsite disposal. Steam generator blowdown and plant drains would be recycled to the cooling tower. Cooling tower blowdown and SAC-SBA wastewater would be fed to the evaporator/crystallizer. Distillate from the evaporator/crystallizer would be recovered to the cooling tower.

ALTERNATIVE 5

This alternative combines Alternative 3 (makeup RO/recovery RO) with an evaporator/crystallizer and would essentially eliminate a liquid waste stream, i.e. there would be no evaporation pond in this alternative. Crystallizer solid waste would require offsite disposal. Steam generator blowdown and plant drains would be recycled to the cooling tower. Cooling tower blowdown and makeup RO wastewater (known as reject) would be fed to the evaporator/crystallizer. Distillate from the evaporator/crystallizer would be recovered to the cooling tower.

COST ANALYSIS

Refer to the following table for a cost analysis of BSEP onsite wells versus offsite brackish water. From a capital perspective Alternative 1 (SAC-SBA) and Alternative 2 (SAC-SBA with recovery RO) are the least costly of the offsite alternatives (i.e. at this level of evaluation they are too close to call). Alternative 3 is the least costly based on operating costs. Relative to the BSEP treatment, Alternatives 1 or 2 would cost an additional $12.0 to $12.5 million to install. Likewise, Alternative 3 (makeup & recovery RO) would cost $1 million more to operate relative to the BSEP base case. When the installed cost is capitalized (amortized at 7% for 20 years), Alternative 3 is the least costly of the five offsite alternatives. However, its annual cost would exceed BSEP costs by over $2.75 million per year.

Lastly, Alternatives 1, 2 or 3 achieve the goal of using non-potable quality water for project cooling. Given the budget level of analysis, the costs of these alternatives are quite close and should be considered equivalent.

Water Treatment Summary & Cost Analysis						
Typical Summer Conditions Basis						
		Offsite Wells - Koehn Lake Source Water				
	BSEP Onsite Wells SAC-SBA	Alternative 1 SAC-SBA	Alternative 2 SAC-SBA Recov RO	Alternative 3 MU RO Recov RO	Alternative 4 SAC-SBA Evap-Crys	Alternative 5 MU-Recov RO Evap-Crys
Equipment & Evap Pond Installed Cost						
SAC-SBA	$20,610,000	$20,610,000	$20,610,000	N/A	$20,610,000	N/A
MU-Recovery RO	N/A	N/A	$3,380,000	$23,840,000	N/A	$21,160,000
Evaporator Crystallizer	N/A	N/A	N/A	N/A	$33,750,000	$36,190,000
Common Tankage & Pumping	$11,140,000	$11,270,000	$10,520,000	$10,970,000	$9,770,000	$9,810,000
Water Treatment Subtotal	$31,750,000	$31,880,000	$34,510,000	$34,810,000	$64,130,000	$67,160,000
Evaporation Pond	$10,960,000	$12,460,000	$10,820,000	$15,340,000	N/A	N/A
Total Water & Wastewater	$42,710,000	$44,340,000	$45,330,000	$50,150,000	$64,130,000	$67,160,000
Pipeline from Koehn Lake						
4 Wells	N/A	$880,000	$880,000	$880,000	$880,000	$880,000
Pump Station	N/A	$3,080,000	$3,000,000	$3,050,000	$2,910,000	$2,910,000
5 Mile Carbon Steel Pipeline	N/A	$6,970,000	$5,580,000	$6,970,000	$5,580,000	$5,580,000
Total	N/A	$10,930,000	$9,460,000	$10,900,000	$9,370,000	$9,370,000
Total Installed Water Treatment Costs	$42,710,000	$55,270,000	$54,790,000	$61,050,000	$73,500,000	$76,530,000
	Base	$12,560,000	$12,080,000	$18,340,000	$30,790,000	$33,820,000
Total Annual Operating Costs	$1,215,000	$3,549,000	$3,453,000	$2,235,000	$5,202,000	$4,215,000
	Base	$2,334,000	$2,238,000	$1,020,000	$3,987,000	$3,000,000
Capitalized Equipment Costs[1]	$4,032,000	$5,218,000	$5,172,000	$5,763,000	$6,938,000	$7,224,000
	Base	$1,186,000	$1,140,000	$1,731,000	$2,906,000	$3,192,000
Annual Operating & Capital Cost	$5,247,000	$8,767,000	$8,625,000	$7,998,000	$12,140,000	$11,439,000
	Base	$3,520,000	$3,378,000	$2,751,000	$6,893,000	$6,192,000

Notes.....

1. Capitalized at 7% per year for 20 years.

DRY COOLING

BSEP evaluated three Air Cooled Condenser (ACC) dry cooling alternatives (refer to Worley Parsons report “FPLE Beacon Solar Energy Project Dry Cooling Evaluation”, dated February 1, 2008). The report evaluated three inlet temperature differences (ITD) scenarios (35 °F, 40 °F and 45 °F). Each ITD scenario yields a slightly different operating profile. For evaluation purposes, the 40 °F scenario was compared to wet cooling alternatives, i.e. the BSEP base case and Alternative 3 (offsite water, MU/Recovery RO). In the Worley Parsons study, the cost for solar arrays was increased to provide 250 MW (i.e. same as base case).

Refer to the following table. Note that the cooling system (cooling tower) costs remain the same for the base case and Alternative 3. After adjusting the costs for water treatment, the BSEP base case is the lowest estimated capital cost followed by Alternative 3 ($18.3 million difference) and dry cooling ($53.7 million difference). The annual operating costs were calculated by adding power for the wet and dry cooling system to the annual cost for water treatment. Other power costs (outside the cooling loop) were considered equivalent. The dry cooling alternative has the lowest operating costs by $403,000 when compared to the BSEP base case.

Cooling System Comparison Summary

Typical Summer Conditions Basis

	BSEP Base Case	Alternative 3 Offsite Wells MU/Recov RO	Alternative 6 Dry Cooling ACC 40F ITD
Cooling System			
Cooling Tower Cells	11		N/A
ACC Cells	N/A		40
Power Requirements			
Fan Power, HP	250		200
Circ Pump Power, HP	2509		N/A
Total Power, HP	5259		8000
Total Power, kw	3918		5960
Average Op Capacity	26.5%		26.5%
Power, kw-hr/year	9,096,000		13,836,000
Power Cost, $/year	$1,364,400	$1,364,400	$2,075,400
Cooling System Costs			
HTF Pumps	$3,000,000		$3,000,000
BFW Pumps	$2,300,000		$2,400,000
SG Heat Exchanger	$12,500,000		$14,100,000
Additional Solar Arrays[1] (installed)	Base		$53,000,000
Cooling Tower	$4,275,000		N/A
CT Basin	$1,500,000		N/A
Circ Water Pumps	$600,000		N/A
Surface Condenser	$3,500,000		N/A
Circ Water Piping	$1,300,000		N/A
Circ Water Piping Install	$520,000		N/A
ACC Equipment	N/A		$36,900,000
ACC Install	N/A		$11,500,000
Closed Cycle Aux Cooler	N/A		$450,000
Total Cooling System Cost	$29,495,000	$29,495,000	$121,350,000
Water Treatment Costs	$42,710,000	$61,050,000	$4,600,000
Total System Cost	$72,205,000	$90,545,000	$125,950,000
	Base	$18,340,000	$53,745,000
Annual Operating Costs			
Water Treatment	$1,215,000	$2,235,000	$101,000
Cooling System Power	$1,364,400	$1,364,400	$2,075,400
Total Operating Cost[2]	$2,579,400	$3,599,400	$2,176,400
	Base	$1,020,000	-$403,000
Capitalized Equipment Costs[3]	$6,820,000	$8,550,000	$11,890,000
	Base	$1,730,000	$5,070,000
Annual Operating & Capital Costs	$9,399,400	$12,149,400	$14,066,400
	Base	$2,750,000	$4,667,000

Notes.....

1. Costs extracted from Worley Parsons report, "FPLE - Beacon Solar Energy Project Dry Cooling Evaluation" dated February 1, 2008.
2. Water treatment costs plus cost for cooling system power. All other power costs were assumed to be equivalent.
3. Capitalized at 7% per year for 20 years.

EFFICIENCY LOSS CALCULATIONS

The Worley Parsons study determined that the net output for the 40 °F ITD ACC would be 7.50 percent less than that of the base case. The base case would include the BSEP proposed cooling configuration or Alternative 3 (offsite wells with makeup and recovery RO). At high ambient dry bulb temperatures (summer conditions), the ACC cannot cool as efficiently as wet cooling resulting in higher condenser backpressure and reduced turbine output. Refer to the following table for a comparison of annual net output for these alternatives. The difference in generating output is an indirect measure of ACC cooling efficiency relative to wet cooling.

Net Output Comparisons			
	BSEP Wet Cooling	Alternative 3 Offsite Wells MU/Recov RO	ACC 40° F ITD
Estimated Annual Output, MW-hr	602,527	602,527	557,365
Est Annual Output Difference, MW-hr	Base	Base	45,162
Pct Difference to Base	Base	Base	-7.50%

REFERENCES

BCV 2009a – Boulder City View (tn 50615). Article El Dorado Energy Solar, Sempra Generation Boulder City View, dated 03/19/09. Submitted to CEC/Docket Unit on 03/20/09.

BLM 2009a – Bureau of Land Management (tn 50618). BLM Project Application Table (PV only). Submitted to CEC/Docket Unit on 03/20/09.

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CEC 2009j – California Energy Commission/E. Solorio (tn 50553). PV – Installed Cost Per Watt, dated on 03/16/09. Submitted to CEC/Docket Unit on 03/18/09.

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DB 2009m – Downey Brand, LLP (tn 50634). Status Report #4, dated 03/02/09. Submitted to CEC/Docket Unit on 03/02/09.

DFG 2008b - Department of Fish and Game/ W. Loudermilk (tn 46814). Letter in Response to Request for Agency Participation, dated 06/19/08. Submitted to CEC/Docket Unit on 06/30/08.

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GW 2009b – Green Wombat (tn 50561). Woody 2009 B, dated 02/27/09. Submitted to CEC/Docket Unit on 03/18/09.

SB 2009a – Sacramento Bee (tn 50619). Energy Production Takes Toll on Birds, dated 03/20/09. Submitted to CEC/Docket Unit on 03/20/09.

SEIA 2009a – Solar Energy Industries Association (tn 50616). SEIA Major Solar Project, dated 03/10/09. Submitted to CEC/Docket Unit on 03/20/09.

WP 2009a – Worley Parsons (tn 49597). Dry Cooling Evaluation, dated 02/01/08. Submitted to CEC/Docket Unit 01/05/09.

APPENDIX A
FEASIBILITY STUDY OF WATER SUPPLIES AND COOLING SYSTEMS

Michael N. DiFilippo

WATER SUPPLY & COOLING

The Beacon Solar Energy Project (BSEP) would utilize onsite groundwater for all plant needs including cooling and steam generator feedwater as well as potable uses. Cooling will be provided by a mechanical draft cooling tower. Plant wastewater (from all sources) would be sent to evaporation ponds for final disposal. No backup cooling water supply is planned for by the applicant although they offer to use future tertiary treated effluent from California City if it becomes available.

Staff has compared the environmental and economic merits of the proposed project with an alternate water supply and one cooling alternative as follows:

PROPOSED PROJECT

All BSEP water needs (including potable needs) will be met by groundwater pumped from wells on the plant site. There are 12 existing water supply wells that were previously used for farming at the site - four wells would be used to supply water for the project (two operating and two backup). The applicant projects water use as follows:

Water Use			
Water Use	Annualized Average Rate[1], gpm	Peak Rate[2], gpm	Estimated Annual Use, Acre Feet
Plant Operation	990	4,054	1,599
Potable Water	5	5	8
1. The estimated groundwater usage in gallons per minute is based on an average daily consumption.			
2. The peak rate is the instantaneous maximum for summer usage.			

Water uses would include cooling tower makeup, closed cooling system makeup, steam generator makeup, mirror washing, plant wash down (housekeeping and maintenance), dilution water for chemical feed systems, etc. Well water would also be used for potable uses - drinking, showers, sinks, and toilets. Well water would be stored on site in the Raw Water Tank. Most of the water would be treated using ion exchange (SAC-SBA) and stored in the Process Water Tank. Process water would be used for cooling tower makeup. A portion of the process water would be treated further for steam generator makeup and mirror washing utilizing portable demineralizers (these are regenerated offsite and generate no wastewater). Wastewater sources include cooling tower blowdown, steam generator blowdown, plant drains, water treatment waste streams, etc. Cooling tower blowdown and SAC-SBA neutralized wastewater would be sent to three 8.3 acre evaporation ponds. Steam generator blowdown and plant drains would be recycled to the cooling tower. The applicant claims that the ponds are sized to accommodate all solids residue generated throughout the life of the plant.

The treatment process selected by BSEP was driven by the PM10 requirements placed on the cooling tower (by the AQMD). The total dissolved solids (TDS) of the circulating water must be less than 1,600 mg/l to meet the PM10 limit. Also, BSEP plans to operate the cooling tower at 15 cycles of concentration (the ratio of feedwater flow to blowdown flow is 15) to minimize wastewater generation. This also means that the TDS of the makeup water (onsite wells) must be reduced to approximately 100 mg/l. BSEP proposes using SAC-SBA ion exchangers to accomplish this. SAC-SBA vessels contain ion exchange resin specifically designed to remove cations (positive ions) and anions (negative ions) from water. The SAC and SBA vessels have a fixed capacity to remove ions, and therefore, must be removed from service frequently and regenerated. This is accomplished by passing dilute sulfuric acid through the SAC vessel (strong acid cation) and dilute sodium hydroxide through the SBA vessel (strong base anion). Wastewater which can have very high or low pH would require neutralization prior to disposal.

In the applicant's water balance for typical annual conditions, they show a wastewater rate to the evaporation ponds of 471 gpm (Section 2, Figure 2-13). This consists primarily of cooling tower blowdown and wastewater from water treatment. They plan to operate at an annual 26.5 percent capacity factor (94% capacity factor during daylight periods). Adjusting wastewater flow to a 24-hour operating basis, flow to the evaporation ponds would be 125 gpm (471 gpm x 26.5%). All ponds would have to operate for the entire year to accommodate this flow. Stated another way, the evaporation rate from the ponds would have to be 97 inches per year. Evaporation pan data for this area is about 120 inches per year. Pan data is measure of ambient evaporation rate and is measured with a National Weather Service Class A pan (measuring 48" diameter x 10" deep). Past experience in sizing evaporation ponds (by author) was to adjust the Class A pan data by 40 percent to 45 percent for salinity and edge effects. This equates to an adjusted evaporation rate of approximately 66 to 72 inches. As ponds concentrate, high levels of salt inhibit evaporation. Additionally, the size, shape and depth of the pond also reduce evaporation. The ponds as sized are marginal and a fourth pond would likely be required. Also, if water use in the plant is greater than that described in the water balance (Figure 2), additional pond area would be required.

ALTERNATIVE WATER SUPPLY (BRACKISH WATER) AND TREATMENT PROCESSES

As a means of conserving high quality (potable) onsite groundwater, five treatment alternatives were evaluated utilizing offsite brackish water. Refer to the following table. All the alternatives would utilize well water from a brackish makeup source. The water is considered brackish because State Water Resources Control Board, Resolution 75-58 defines brackish waters as "all waters with a salinity range of 1,000 to 30,000 mg/l" and the water at Koehn Lake fits within those parameters. The aquifer is accessible at the southwest corner of Koehn Lake approximately 5 miles from the project site. It was assumed that four wells would be required to supply BSEP needs. In all of the alternatives well water would be transported to the site via a 12-inch or 14-inch pipeline (depending on water demand).

Offsite Brackish Water Alternatives					
	SAC-SBA	Makeup RO	Recovery RO	Evap/Crys	Evap Ponds
Alternative 1	X				X
Alternative 2	X		X		X
Alternative 3		X	X		X
Alternative 4	X			X	
Alternative 5		X	X	X	

All of the processes in the above table are well established commercial technologies.

SAC-SBA in Alternative 1 is the same ion exchange process proposed by BSEP.

Reverse osmosis (RO) would be used in two ways – as makeup treatment or in a wastewater recovery configuration. In alternatives 2 and 5, RO would be used to directly treat cooling tower makeup, steam generator makeup and mirror washing water. In Alternatives 2, 3 and 5, RO would be used to treat cooling tower blowdown to reduce overall wastewater volume either for disposal or as a pretreatment to an evaporator. RO is a technology that utilizes permeable membranes (under relatively high pressure) to repel salt and pass water. Most of the dissolved salts are repelled by the membrane surface (95% to 98% for most ions) allowing only water to pass through. RO must have highly filtered water with modified chemistry (usually pH adjustment) to operate successfully. In the alternatives utilizing RO, the water would be filtered by the use of microfiltration (MF). MF is also a membrane process that is commonly used with RO in difficult industrial or reuse applications.

Evaporator/Crystallizers in Alternatives 4 and 5 would be used to reduce wastewater volume to essentially zero volume. In the evaporator 90 percent to 95 percent of the water would be recovered. Brine from the evaporator would be sent to a crystallizer to further recover water. Waste from the crystallizer would be in the form of highly concentrated salt brines that would crystallize to solid form for offsite disposal. In Alternative 5, a recovery RO would be used to pre-concentrate the wastewater stream to the evaporator. Alternatives 4 and 5 would be the only treatment options requiring offsite disposal.

COMPARATIVE WATER CONSUMTION OF VARIOUS PROCESSES

Refer to the following table for a comparative summary of onsite water versus offsite brackish water for BSEP makeup. The analysis was based on typical summer conditions. Note the evaporation pond sizing for the BSEP proposed treatment. Staff calculated a pond size (utilizing the criteria discussed above) of 43.5 acres versus 25 acres in the BSEP project description.

Water Treatment Summary						
Typical Summer Conditions Basis						
		Offsite Wells - Koehn Lake Source Water				
	BSEP Onsite Wells SAC-SBA	Alternative 1 SAC-SBA	Alternative 2 SAC-SBA Recov RO	Alternative 3 MU RO Recov RO	Alternative 4 SAC-SBA Evap-Crys	Alternative 5 MU-Recov RO Evap-Crys
Water Demand - Instantaneous						
Onsite Wells Demand, gpm	4,038	5	5	5	5	5
Koehn Lake Water Demand, gpm	N/A	4,086	3,772	3,959	3,463	3,480
Total Wastewater, gpm	572	650	565	801	0	0
Water Demand - Annual Average Conditions						
Annual Capacity Factor	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
Onsite Wells Demand, gpm	1,070	5	5	5	5	5
Koehn Lake Water Demand, gpm	N/A	1,083	1,000	1,049	918	922
Onsite Wells Demand, AF/yr	1,726	8.1	8.1	8.1	8.1	8.1
Koehn Lake Water Demand, AF/yr	N/A	1,747	1,612	1,692	1,480	1,488
Total Wastewater, gpm	152	172	150	212	0	0
Evap Pond, acres[1]	43.5	49.4	42.9	60.8	0	0

Notes.....

1. BSEP project evap pond was sized based based on staff calculation.

The offsite well field at Koehn Lake would be the same for all of the alternatives (1 through 5). Each well was assumed to be 500 feet deep. The pipeline diameter for Alternatives 1 and 3 is 14 inches and 12 inches for Alternatives 2, 4 and 5. The size differences are a function of water demand for each alternative. For this analysis, the line was sized to operate 24 hours per day at half the water demand rate.

ALTERNATIVE 1

Alternative 1 utilizes “brackish” water from offsite wells for plant needs, e.g. cooling tower makeup, closed cooling system makeup, steam generator makeup, mirror washing, etc. Steam generator blowdown and plant drains would be recycled to the cooling tower. It is the same alternative proposed by BSEP. Well water from onsite wells would still be used for potable needs. Plant wastewater would be sent to an evaporation pond for final disposal. The evaporation ponds would be about 15 percent larger than the BSEP ponds because more wastewater would be generated by the SAC-SBA treating brackish water.

ALTERNATIVE 2

This alternative combines Alternative 1 (SAC-SBA) with a recovery RO to reduce the cooling tower blowdown portion of the wastewater stream. MF would be used as pretreatment for the recovery RO. The evaporation ponds would be slightly smaller than the BSEP ponds.

ALTERNATIVE 3

In this alternative offsite water would be treated with and RO prior to storage in the Process Water Tank (replacing SAC-SBA). A portion of cooling tower blowdown would also be recovered via RO prior to discharge to evaporation ponds. MF would be used as pretreatment for the makeup and recovery RO. Steam generator blowdown and plant drains would be recycled to the cooling tower. RO permeate would be recovered to the cooling tower. This alternative would generate more wastewater than Alternatives 1 or 2 and would require a significantly larger evaporation pond.

ALTERNATIVE 4

This alternative combines Alternative 1 (SAC-SBA) with an evaporator/crystallizer and would essentially eliminate a liquid waste stream. There would be no evaporation pond in this alternative. Crystallizer solid waste would require offsite disposal. Steam generator blowdown and plant drains would be recycled to the cooling tower. Cooling tower blowdown and SAC-SBA wastewater would be fed to the evaporator/crystallizer. Distillate from the evaporator/crystallizer would be recovered to the cooling tower.

ALTERNATIVE 5

This alternative combines Alternative 3 (makeup RO/recovery RO) with an evaporator/crystallizer and would essentially eliminate a liquid waste stream, i.e. there would be no evaporation pond in this alternative. Crystallizer solid waste would require offsite disposal. Steam generator blowdown and plant drains would be recycled to the cooling tower. Cooling tower blowdown and makeup RO wastewater (known as reject) would be fed to the evaporator/crystallizer. Distillate from the evaporator/crystallizer would be recovered to the cooling tower.

COST ANALYSIS

Refer to the following table for a cost analysis of BSEP onsite wells versus offsite brackish water. From a capital perspective Alternative 1 (SAC-SBA) and Alternative 2 (SAC-SBA with recovery RO) are the least costly of the offsite alternatives (i.e. at this level of evaluation they are too close to call). Alternative 3 is the least costly based on operating costs. Relative to the BSEP treatment, Alternatives 1 or 2 would cost an additional $12.0 to $12.5 million to install. Likewise, Alternative 3 (makeup & recovery RO) would cost $1 million more to operate relative to the BSEP base case. When the installed cost is capitalized (amortized at 7% for 20 years), Alternative 3 is the least costly of the five offsite alternatives. However, its annual cost would exceed BSEP costs by over $2.75 million per year.

Lastly, Alternatives 1, 2 or 3 achieve the goal of using non-potable quality water for project cooling. Given the budget level of analysis, the costs of these alternatives are quite close and should be considered equivalent.

Water Treatment Summary & Cost Analysis						
Typical Summer Conditions Basis						
		Offsite Wells - Koehn Lake Source Water				
	BSEP	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5
	Onsite Wells		SAC-SBA	MU RO	SAC-SBA	MU-Recov RO
	SAC-SBA	SAC-SBA	Recov RO	Recov RO	Evap-Crys	Evap-Crys
Equipment & Evap Pond Installed Cost						
SAC-SBA	$20,610,000	$20,610,000	$20,610,000	N/A	$20,610,000	N/A
MU-Recovery RO	N/A	N/A	$3,380,000	$23,840,000	N/A	$21,160,000
Evaporator Crystallizer	N/A	N/A	N/A	N/A	$33,750,000	$36,190,000
Common Tankage & Pumping	$11,140,000	$11,270,000	$10,520,000	$10,970,000	$9,770,000	$9,810,000
Water Treatment Subtotal	$31,750,000	$31,880,000	$34,510,000	$34,810,000	$64,130,000	$67,160,000
Evaporation Pond	$10,960,000	$12,460,000	$10,820,000	$15,340,000	N/A	N/A
Total Water & Wastewater	$42,710,000	$44,340,000	$45,330,000	$50,150,000	$64,130,000	$67,160,000
Pipeline from Koehn Lake						
4 Wells	N/A	$880,000	$880,000	$880,000	$880,000	$880,000
Pump Station	N/A	$3,080,000	$3,000,000	$3,050,000	$2,910,000	$2,910,000
5 Mile Carbon Steel Pipeline	N/A	$6,970,000	$5,580,000	$6,970,000	$5,580,000	$5,580,000
Total	N/A	$10,930,000	$9,460,000	$10,900,000	$9,370,000	$9,370,000
Total Installed Water Treatment Costs	$42,710,000	$55,270,000	$54,790,000	$61,050,000	$73,500,000	$76,530,000
	Base	$12,560,000	$12,080,000	$18,340,000	$30,790,000	$33,820,000
Total Annual Operating Costs	$1,215,000	$3,549,000	$3,453,000	$2,235,000	$5,202,000	$4,215,000
	Base	$2,334,000	$2,238,000	$1,020,000	$3,987,000	$3,000,000
Capitalized Equipment Costs[1]	$4,032,000	$5,218,000	$5,172,000	$5,763,000	$6,938,000	$7,224,000
	Base	$1,186,000	$1,140,000	$1,731,000	$2,906,000	$3,192,000
Annual Operating & Capital Cost	$5,247,000	$8,767,000	$8,625,000	$7,998,000	$12,140,000	$11,439,000
	Base	$3,520,000	$3,378,000	$2,751,000	$6,893,000	$6,192,000

Notes.....

1. Capitalized at 7% per year for 20 years.

DRY COOLING

BSEP evaluated three Air Cooled Condenser (ACC) dry cooling alternatives (refer to Worley Parsons report “FPLE Beacon Solar Energy Project Dry Cooling Evaluation”, dated February 1, 2008). The report evaluated three inlet temperature differences (ITD) scenarios (35 °F, 40 °F and 45 °F). Each ITD scenario yields a slightly different operating profile. For evaluation purposes, the 40 °F scenario was compared to wet cooling alternatives, i.e. the BSEP base case and Alternative 3 (offsite water, MU/Recovery RO). In the Worley Parsons study, the cost for solar arrays was increased to provide 250 MW (i.e. same as base case).

Refer to the following table. Note that the cooling system (cooling tower) costs remain the same for the base case and Alternative 3. After adjusting the costs for water treatment, the BSEP base case is the lowest estimated capital cost followed by Alternative 3 ($18.3 million difference) and dry cooling ($53.7 million difference). The annual operating costs were calculated by adding power for the wet and dry cooling system to the annual cost for water treatment. Other power costs (outside the cooling loop) were considered equivalent. The dry cooling alternative has the lowest operating costs by $403,000 when compared to the BSEP base case.

Cooling System Comparison Summary

Typical Summer Conditions Basis

	BSEP Base Case	Alternative 3 Offsite Wells MU/Recov RO	Alternative 6 Dry Cooling ACC 40F ITD
Cooling System			
Cooling Tower Cells	11		N/A
ACC Cells	N/A		40
Power Requirements			
Fan Power, HP	250		200
Circ Pump Power, HP	2509		N/A
Total Power, HP	5259		8000
Total Power, kw	3918		5960
Average Op Capacity	26.5%		26.5%
Power, kw-hr/year	9,096,000		13,836,000
Power Cost, $/year	$1,364,400	$1,364,400	$2,075,400
Cooling System Costs			
HTF Pumps	$3,000,000		$3,000,000
BFW Pumps	$2,300,000		$2,400,000
SG Heat Exchanger	$12,500,000		$14,100,000
Additional Solar Arrays[1] (installed)	Base		$53,000,000
Cooling Tower	$4,275,000		N/A
CT Basin	$1,500,000		N/A
Circ Water Pumps	$600,000		N/A
Surface Condenser	$3,500,000		N/A
Circ Water Piping	$1,300,000		N/A
Circ Water Piping Install	$520,000		N/A
ACC Equipment	N/A		$36,900,000
ACC Install	N/A		$11,500,000
Closed Cycle Aux Cooler	N/A		$450,000
Total Cooling System Cost	$29,495,000	$29,495,000	$121,350,000
Water Treatment Costs	$42,710,000	$61,050,000	$4,600,000
Total System Cost	$72,205,000	$90,545,000	$125,950,000
	Base	$18,340,000	$53,745,000
Annual Operating Costs			
Water Treatment	$1,215,000	$2,235,000	$101,000
Cooling System Power	$1,364,400	$1,364,400	$2,075,400
Total Operating Cost[2]	$2,579,400	$3,599,400	$2,176,400
	Base	$1,020,000	-$403,000
Capitalized Equipment Costs[3]	$6,820,000	$8,550,000	$11,890,000
	Base	$1,730,000	$5,070,000
Annual Operating & Capital Costs	$9,399,400	$12,149,400	$14,066,400
	Base	$2,750,000	$4,667,000

Notes.....

1. Costs extracted from Worley Parsons report, "FPLE - Beacon Solar Energy Project Dry Cooling Evaluation" dated February 1, 2008.
2. Water treatment costs plus cost for cooling system power. All other power costs were assumed to be equivalent.
3. Capitalized at 7% per year for 20 years.

EFFICIENCY LOSS CALCULATIONS

The Worley Parsons study determined that the net output for the 40 °F ITD ACC would be 7.50 percent less than that of the base case. The base case would include the BSEP proposed cooling configuration or Alternative 3 (offsite wells with makeup and recovery RO). At high ambient dry bulb temperatures (summer conditions), the ACC cannot cool as efficiently as wet cooling resulting in higher condenser backpressure and reduced turbine output. Refer to the following table for a comparison of annual net output for these alternatives. The difference in generating output is an indirect measure of ACC cooling efficiency relative to wet cooling.

Net Output Comparisons

	BSEP Wet Cooling	Alternative 3 Offsite Wells MU/Recov RO	ACC 40° F ITD
Estimated Annual Output, MW-hr	602,527	602,527	557,365
Est Annual Output Difference, MW-hr	Base	Base	45,162
Pct Difference to Base	Base	Base	-7.50%

REFERENCES

BCV 2009a – Boulder City View (tn 50615). Article El Dorado Energy Solar, Sempra Generation Boulder City View, dated 03/19/09. Submitted to CEC/Docket Unit on 03/20/09.

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GW 2009b – Green Wombat (tn 50561). Woody 2009 B, dated 02/27/09. Submitted to CEC/Docket Unit on 03/18/09.

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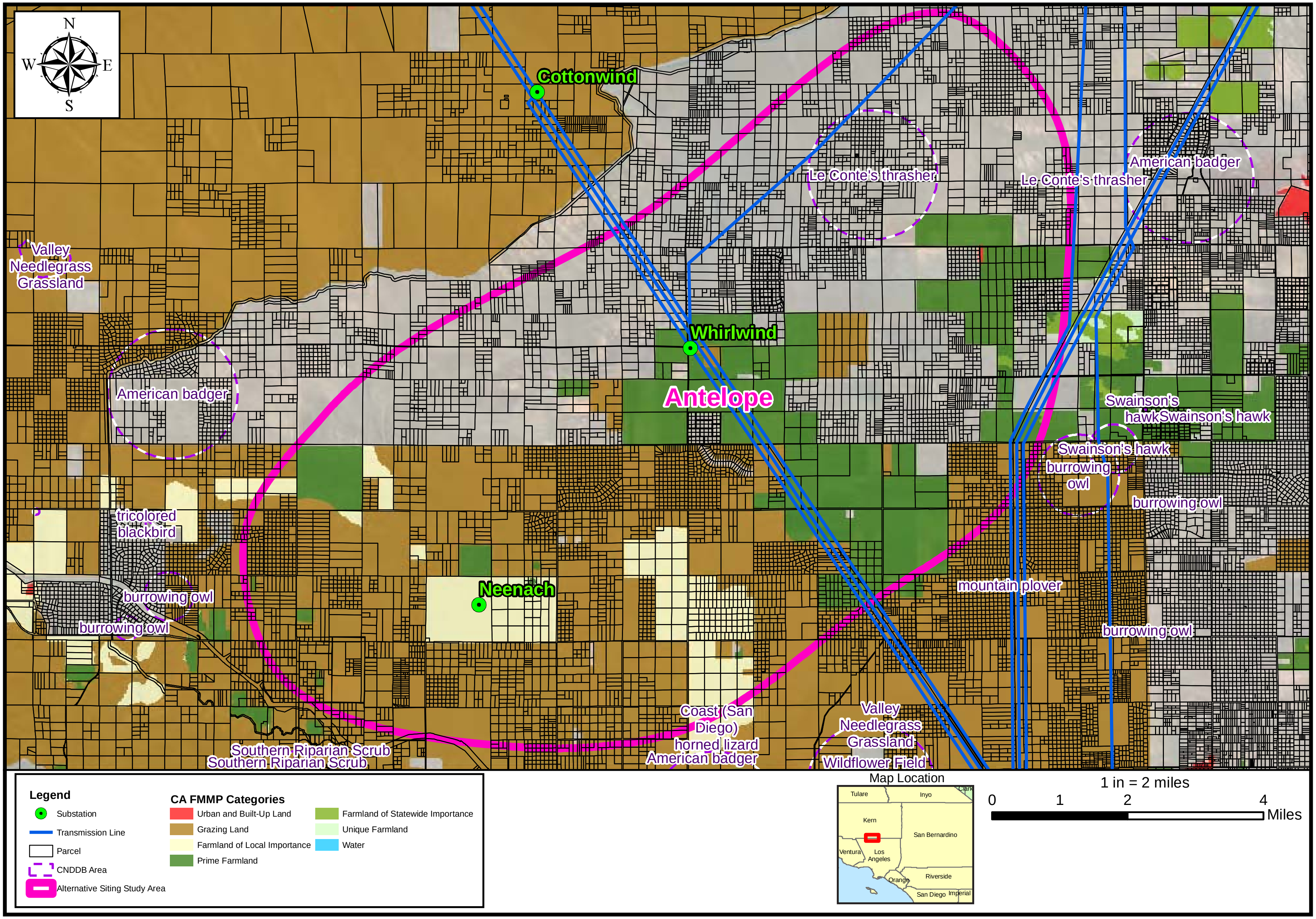
WP 2009a – Worley Parsons (tn 49597). Dry Cooling Evaluation, dated 02/01/08. Submitted to CEC/Docket Unit 01/05/09.

ALTERNATIVES - FIGURE 1

Beacon Solar Energy Project - Antelope Site Alternative

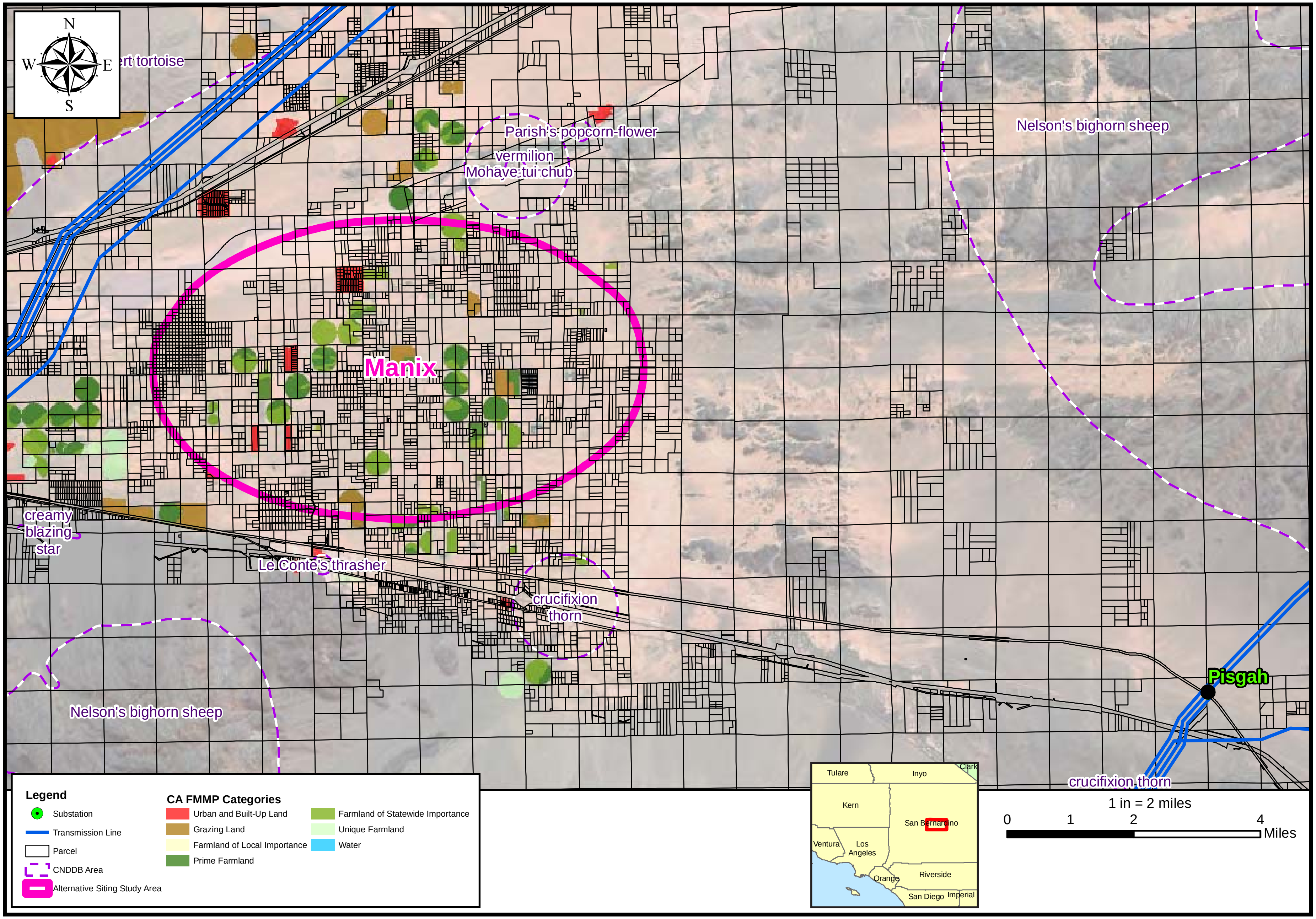


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: Pg. 6 of NER 2009a

ALTERNATIVES - FIGURE 2

Beacon Solar Energy Project - Manix Site Alternative

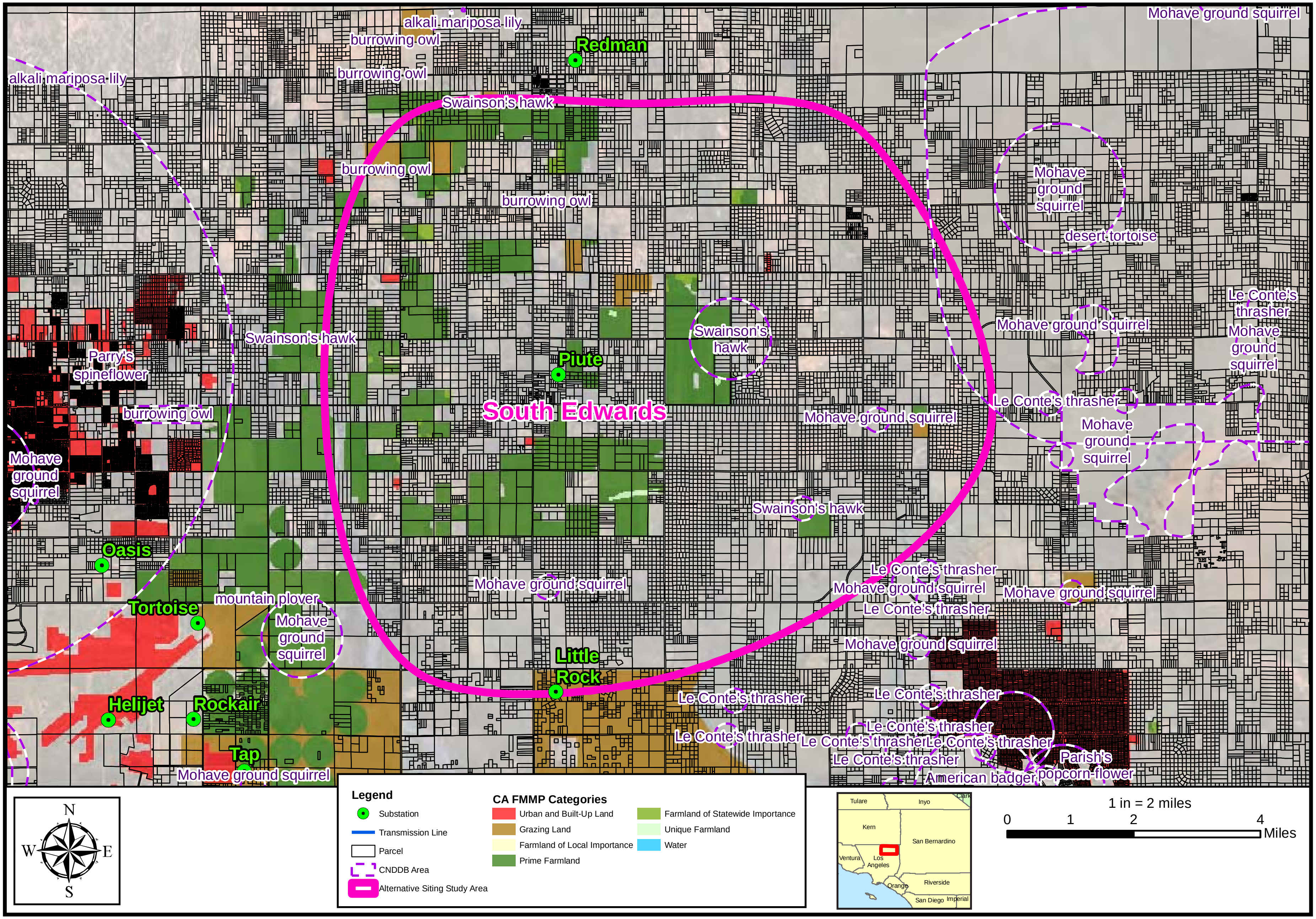


CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: Pg. 3 of NER 2009a

ALTERNATIVES - FIGURE 3

Beacon Solar Energy Project - South Edwards Site Alternative



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION, APRIL 2009

SOURCE: Pg. 4 of NER 2009a

GENERAL CONDITIONS
INCLUDING
COMPLIANCE MONITORING AND CLOSURE PLAN

Steve Munro

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 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

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 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):

- All documents demonstrating compliance with any legal requirements relating to the construction and operation of the facility;
- All monthly and annual compliance reports filed by the project owner;
- All complaints of noncompliance filed with the Energy Commission; and
- 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:

> **<u>Compliance Project Manager</u>**
(08-AFC-2C)
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.

<u>Pre-Construction Matrix and Tasks Prior to Start of Construction (COMPLIANCE-4)</u>

Prior to commencing construction, a compliance matrix addressing <u>only</u> 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; and

7. the compliance status of each condition, e.g., "not started," "in progress" or "completed" (include the date).

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 this section.**

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 (fully satisfied conditions do not need to be included in the matrix after they have been reported as completed);

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 Dockets Unit 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. The amount of the fee for FY2007-2008 was $17,676. The initial payment is due on the date the Energy Commission adopts the final decision. You will be notified of the amount due. 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 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 30 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 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 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, Insignificant Project Changes 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 **insignificant project changes** 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 you with 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 you with a sample petition to use as a template.

Insignificant Project Change

Modifications that do not result in deletions or changes to conditions of certification, and that are compliant with laws, ordinances, regulations and standards may be authorized by the CPM as an insignificant project change pursuant to section 1769(a) (2). This process usually requires minimal time to complete, and it requires a 14-day public review of the Notice of Insignificant Project Change that includes staff's intention to approve the modification unless substantive objections are filed. These requests must also be submitted in the form of a "petition to amend" as described above.

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.

The Energy Commission has established a toll free compliance telephone number of **1-800-858-0784** for the public to contact the Energy Commission about power plant construction or operation-related questions, complaints or concerns.

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 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.

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	

COMPLIANCE TABLE 1
SUMMARY of COMPLIANCE CONDITIONS OF CERTIFICATION

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.

CONDITION NUMBER	SUBJECT	DESCRIPTION
COMPLIANCE-8	Confidential Information	Any information the project owner deems confidential shall be submitted to the Energy Commission's Dockets Unit 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.

ATTACHMENT A

COMPLAINT REPORT/RESOLUTION FORM

PROJECT NAME: AFC Number:
COMPLAINT LOG NUMBER ____________ Complainant's name and address: Phone number: ____________________
Date and time complaint received: Indicate if by telephone or in writing (attach copy if written): Date of first occurrence:
Description of complaint (including dates, frequency, and duration):
Findings of investigation by plant personnel: Indicate if complaint relates to violation of a CEC requirement: Date complainant contacted to discuss findings: ___________________
Description of corrective measures taken or other complaint resolution: Indicate if complainant agrees with proposed resolution: If not, explain: Other relevant information:
If corrective action necessary, date 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: ______________________________ Date:

(Attach additional pages and supporting documentation, as required.)

PREPARATION TEAM

BEACON SOLAR ENERGY PROJECT
PREPARATION TEAM

Executive Summary .... Eric K. Solorio

Introduction .... Eric K. Solorio

Project Description .... Eric K. Solorio

Air Quality.. William Walters, P.E.

Biological Resources .... Susan Sanders

Cultural Resources............ Michael D. McGuirt, Amanda Blosser, and Beverly E. Bastian

Hazardous Materials Management.................................. Geoff Lesh, PE and Rick Tyler

Land Use .... James Adams

Noise and Vibration .... Erin Bright and Steve Baker

Public Health .... Obed Odoemelam, Ph.D.

Socioeconomic Resources .... Marie Mclean

Soils and Water Resources.................. C. Weaver, V. Geronimo, J. Fio, and M. DiFilippo

Traffic and Transportation .... David Flores

Transmission Line Safety and Nuisance .... Obed Odoemelam, Ph.D.

Visual Resources .... Mark R. Hamblin

Waste Management .... Ellie Townsend-Hough

Worker Safety and Fire Protection .... Geoff Lesh, PE and Rick Tyler

Facility Design .... Erin Bright and Steve Baker

Geology and Paleontology .... Dal Hunter, Ph.D., C.E.G.

Power Plant Efficiency .... Shahab Khoshmashrab

Power Plant Reliability .... Shahab Khoshmashrab

Transmission System Engineering .... Sudath Arachchige and Mark Hesters

Alternatives .... Eric K. Solorio

General Conditions Including Compliance Monitoring & Facility Closure ...... Steve Munro

Project Secretary.. .Maria Santourdjian

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 *BEACON SOLAR ENERGY PROJECT*

Docket No. 08-AFC-2

PROOF OF SERVICE
(Revised 2/9/09)

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DECLARATION OF SERVICE

I, Maria Santourdjian, declare that on April 1, 2009, I served and filed copies of the attached Beacon Solar Energy Project (08-AFC-2) Preliminary Staff Assessment. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[www.energy.ca.gov/sitingcases/beacon]**. The document has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

FOR SERVICE TO ALL OTHER PARTIES:

__✓__ sent electronically to all email addresses on the Proof of Service list;

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

AND

FOR FILING WITH THE ENERGY COMMISSION:

__✓__ 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-4
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.

Original Signature in Dockets
Maria Santourdjian