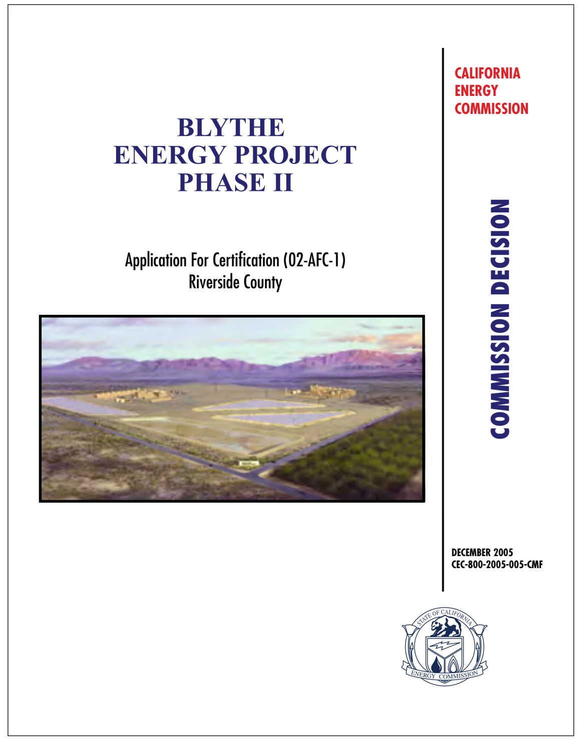
CALIFORNIA
ENERGY
COMMISSION

BLYTHE ENERGY PROJECT PHASE II

Application For Certification (02-AFC-1)
Riverside County

COMMISSION DECISION

DECEMBER 2005
CEC-800-2005-005-CMF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CALIFORNIA ENERGY COMMISSION

1516 9th Street
Sacramento, CA 95814
www.energy ca.gov/sitingcases/blythe2

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EXECUTIVE SUMMARY:

APPROVED
WITH CONDITIONS

The Energy Commission approves the Blythe Energy Project, Phase II (BEP II), a proposed 520-megawatt (MW) combined-cycle facility in Blythe, California, together with the following highlighted measures to mitigate potential environmental and community impacts and comply with applicable laws, ordinances, regulations and standards (LORS):

WATER RESOURCES:	✓ The proposed project will use 3,300 acre-feet of degraded groundwater annually and implement a voluntary Water Conservation Offset Program that will conserve an equivalent amount of fresh Colorado River water.
LAND USE:	✓ The City of Blythe found the project in the public interest and adopted Resolution No. 04-897 placing conditions on the project and overruling any inconsistency determination by the Riverside County Airport Land Use Commission.
TRAFFIC & TRANSPORTATION:	✓ The proposed project will use appropriate pilot notification and avoidance measures to minimize inflight encounters with thermal plumes from the cooling towers and stacks.
BIOLOGY	✓ The proposed project will use a Zero Liquid Discharge process to avoid routinely discharging process wastewater in an evaporation pond.
SOCIOECONOMICS:	✓ A funded Farming Sector Retraining Plan will address the incremental economic effects of the project's Water Conservation Offset Program, which fallows or retires productive farmland.

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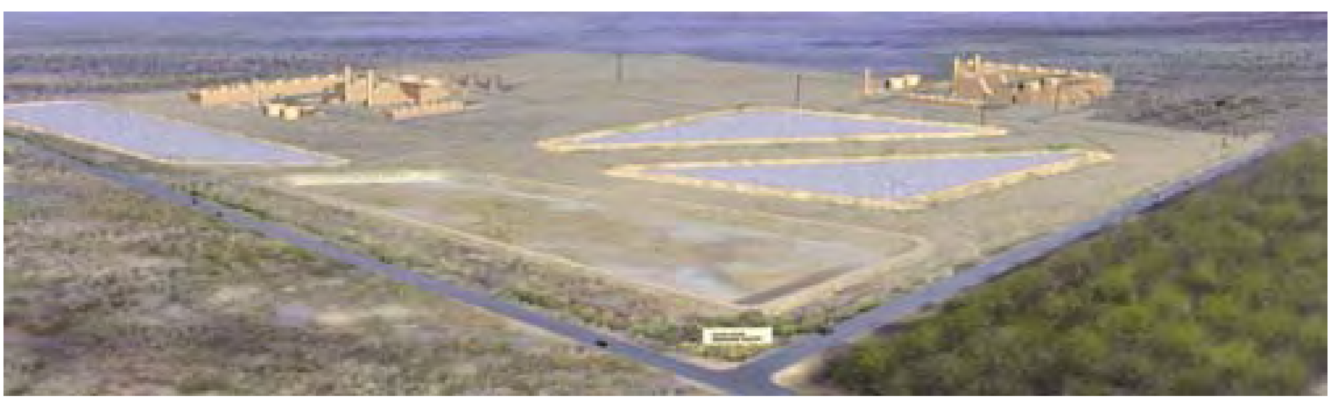
PROJECT DESCRIPTION

- ***PROJECT NAME:*** Blythe Energy Project, Phase II (BEP I)
- ***PROJECT OWNER:*** Caithness Blythe II, LLC
- ***PROJECT OBJECTIVES:*** *(per Project Owner)*

    1. Use a project site adjacent to BEP I;
    2. Use a site that is in close proximity to existing electrical transmission and natural gas facilities;
    3. Utilize a site that has environmental compatibility with an expected low impact on the environment, given its proximity to the industrial lands at the airport and BEP I, remoteness from residential areas, elevation above most populated areas, and low traffic conditions;
    4. Develop a maximally efficient merchant power plant; and
    5. Produce electricity to sell competitively into the regional markets in Southern California and Arizona

- ***FUTURE PROJECT/SITE DEVELOPMENT:*** None proposed. The BEP II power plant proposal fully develops the site adjoining BEP I, certified by the Energy Commission on March 21, 2001, and constitutes the whole of the project.

- ***PROJECT: BEFORE & AFTER:***



- ***PROJECT LOCATION:***
  - Location: Hobsonway & Buck Boulevard, Blythe, California
  - Local Jurisdiction: City of Blythe
  - Zoning: General Industrial (I-G)
  - Air Quality Jurisdiction: Mojave Desert Air Quality Management District (MDAQMD)
  - Seismic Zone: Zone 3
  - Vehicular Access: Regional and interregional vehicular access for the project area is provided by a system of freeway (Interstate-10) and local arterials. Primary access to the site will be from the east on Hobsonway.
  - Site Setting: BEP II is adjacent to the west side of the BEP I site boundary on the Expansion Site approved by the Energy Commission as an amendment to BEP I, when its evaporation ponds were reconfigured. (BEP I is currently owned and operated by Florida Power and Light.) BEP II may utilize some existing facilities at the BEP I site including the BEP I Control/Administration and Maintenance Buildings and the surface water runoff retention basin. Other BEP I facilities that may be expanded to serve BEP II include the groundwater supply, fire protection facilities and site access roads. Natural gas will be supplied to the BEP II plant by the natural gas pipeline constructed as part of BEP I.

    BEP II will be electrically interconnected to the Buck Boulevard Substation, located in the northeastern corner of the BEP I site. BEP II proposes to interconnect to the proposed Desert Southwest Transmission Project (DWSTP), which is currently under permit review by the United States Department of Interior, Bureau of Land Management (BLM).

  - Alternative Locations: No alternative site considered would meet the project objectives and have fewer environmental and community impacts.

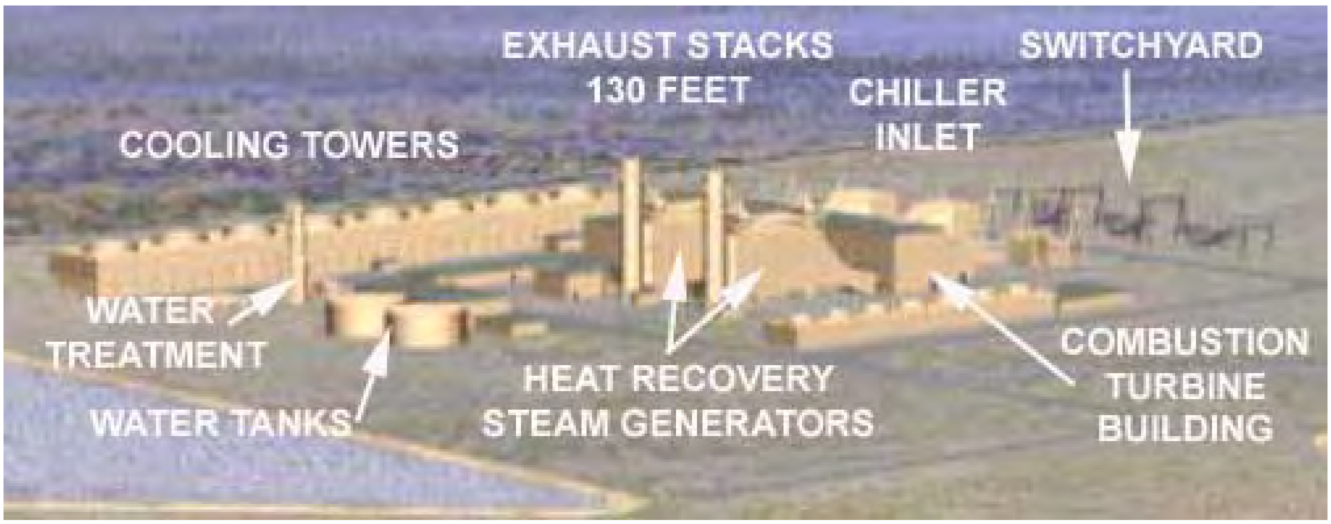
- ***PROJECT DESIGN:***
  - Type: Combined-cycle electric generating facility:
  - Fuel: Natural Gas from existing El Paso Gas System pipeline to BEP I. (No backup fuel)
  - Output: 520 megawatts (MW)
  - Combustion Turbines: Two
  - Manufacturer: Siemens Westinghouse
  - Model/Type: V84.3a (F-Class)
  - Maximum Rated Output: Each combustion gas turbine-generator (CTG) will generate approximately 170 MW (gross).
  - Emission Controls:
    - NOx: Dry low-NOx Burner with SCR will control NOx emission to 2.0 parts per million (ppm).

  - Steam Turbine: One
  - Manufacturer: Siemens
  - Model/Type: Triple-pressure condensing steam turbine.

- Maximum Rated Output: Peak generating output approximately 180 MW.

- Heat Recovery Steam Generator: The HRSGs will recover waste heat from combustion turbine generator exhaust and generate steam at three pressures for injection into the respective section of the steam turbine. The HRSGs include duct firing to generate additional steam output for full capacity.

- Inlet Air Cooler: The combustion gas turbines will be equipped with an inlet cooling system (like an air conditioner), cooling combustion air during hot temperature conditions, thus increasing plant output.



- Cooling Water: The plant proposes to use degraded groundwater from two new 3,000 gallon per minute (gpm) wells constructed on the plant site or immediate area.

- Hazardous Materials On-site: The following are anticipated hazardous materials that will be on-site for purposes of operation: aqueous ammonia, anhydrous ammonia, hydrazine, natural gas, sulfuric acid, hydrogen, diesel fuel, lube oil, mineral oil, propane.

- Wastes & Disposal: Wastes typical of power generation operation including oily rags, broken and rusted metal and machine parts, defective or broken electrical materials, empty containers and other miscellaneous solid wastes including typical refuse will be disposed of in accordance with applicable laws and regulations. Facility wastewaters will be handled through a Zero Liquid Discharge (ZLD) process. A stand-by evaporation pond will be used for processed wastewaters only when the ZLD system is unavailable.

- Tallest Feature: The HRSG exhaust stack structure will be 130-feet tall.

- Alternative Technology Considered: None

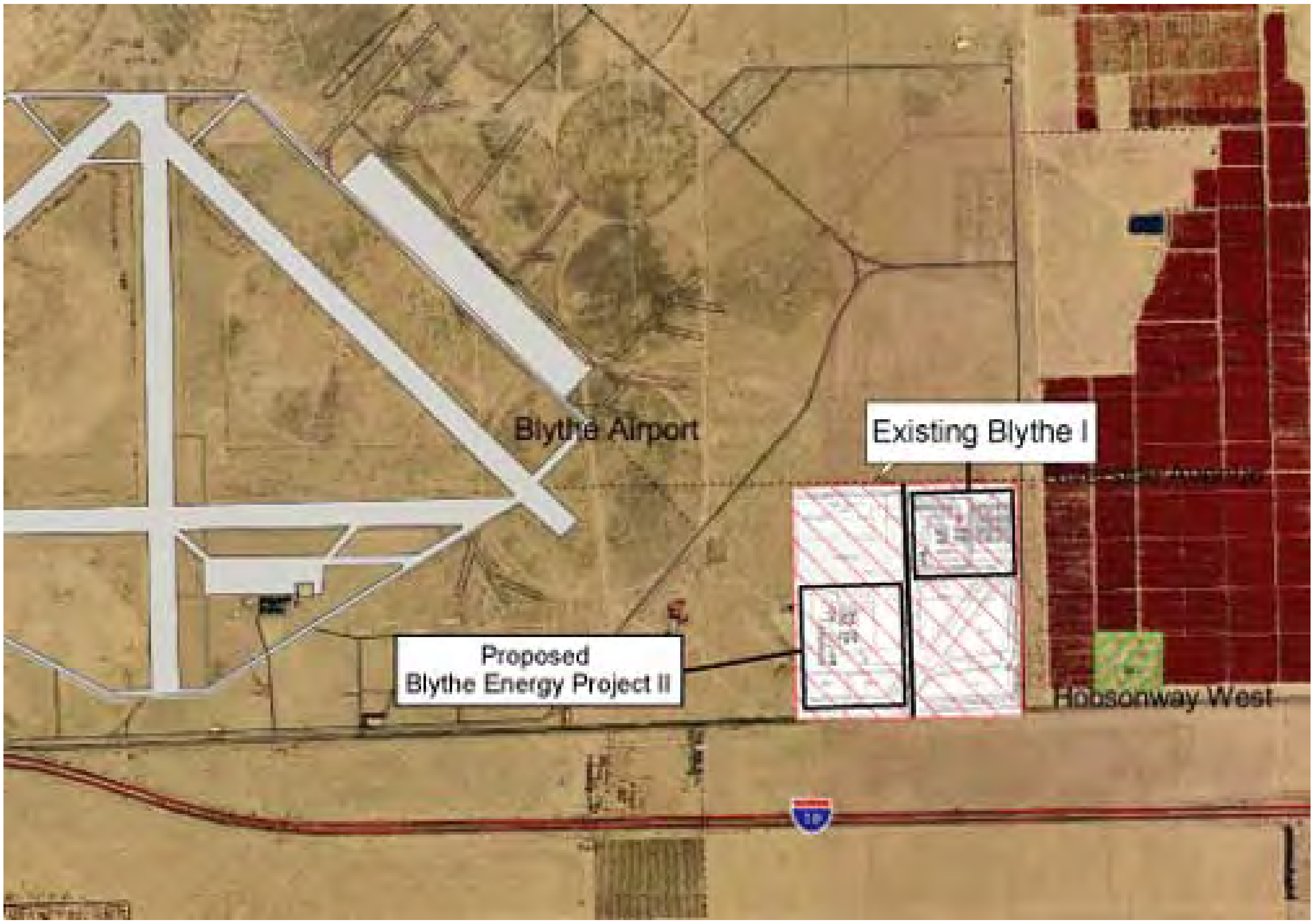
- Alternative Fuel Considered: No alternative fuels were considered.

- Alternative Equipment Considered: Only Best Available Control Technology was considered for this project. Dry cooling was not used due to added costs, reduced output, and inability to meet expected operating profiles.

- ***SURROUNDING SETTING:***

The BEP II site is located on 76 acres within the expanded BEP I site, which totals 152 acres, in the City of Blythe in Riverside County. The BEP II project is located approximately five miles west of the center of the City of Blythe. The site is one mile east of the Blythe Airport, owned by the County of Riverside and operated by the City of Blythe.

The topography of the project site is flat. The BEP sites (BEP I and II) are bounded on the south by Hobsonway and on the east by Buck Boulevard. Hobsonway is a paved highway running east/west parallel to and one-quarter mile north of Interstate 10 (I-10). Buck Boulevard has been paved as part of BEP I. Buck Boulevard runs along the eastern side of the BEP I property line and runs north from Hobsonway. The north boundary of the site is Riverside Avenue that is paved only along the frontage of BEP I. The rest is an unpaved easement dedicated for extending Riverside Avenue.



- ***RELATED FACILITIES***

  - <u>Water Supply</u>
    - Two new 3,000 gallon per minute (gpm) groundwater wells to be constructed to depths of 600 to 620 feet on site or in the immediate area. The groundwater marginally exceeds California's drinking water standards for Total Dissolved Solids (TDS). Water use includes makeup water for the cooling system, makeup water for the steam production system, and potable water for domestic uses. Average use is expected to be 2,200 gpm or approximately 3,300 acre-feet.
    - BEP II has proposed a voluntary Water Conservation Offset Program (WCOP) that would retire or fallow about 786 acres per year of irrigated agricultural lands to offset its water usage.

  - <u>Switchyard</u>
    - BEP II will connect with the existing Buck Boulevard Substation, owned and operated by Western Area Power Administration (WAPA), located in the northeastern corner of the BEP I site.

- <u>Electric Transmission</u>
  - Voltage: 500 kV
  - Type: Existing above-ground
  - Tower Type: New towers on-site, pole structures.
  - Route: No new off-site facilities.
  - Point of Interconnection: At existing on-site Buck Boulevard Switchyard.
  - Foreseeable Effect on Downstream Transmission Facilities: Existing capacity of the interconnected transmission grid from the Buck Boulevard Substation is insufficient to distribute BEP II generation. Construction of BEP II will not begin until the Desert Southwest Transmission Project, which will have sufficient capacity for BEP II, is permitted.
  - Alternative Routes Considered: N/A

- <u>Gas Pipeline</u>
  - An existing 11-mile underground pipeline provides natural gas to BEP from the El Paso Gas System in Arizona. An on-site interconnection pipeline will be constructed from BEP I to BEP II. BEP II will consume approximately 31 million MMbtu per year.

AIR QUALITY – Summary of Findings and Conditions

	PROJECT	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Construction Equipment/ Construction Dust	**MITIGATION**	**None**	**YES**
	Construction: Large construction equipment potentially contributes to existing violations of state 24-hour and annual PM_{10} standards. To minimize PM_{10} emissions, the Project Owner shall require its construction contractors to minimize emissions from diesel-powered earthmoving equipment. **MITIGATION:** ☑ The Project Owner shall require construction contractors to mitigate diesel emissions by measures such as the use of ultra-low sulfur diesel fuel, and use of engines meeting California Off-road Diesel Emission standards or use of catalyzed diesel particulate filters. Condition **AQ-C5**. Grading and excavation activities potentially produce dust that can be transported off-site by wind. These project construction activities would further exacerbate existing violations of the state PM_{10} standards, and thus constitute a significant air quality impact for PM_{10}. To control airborne fugitive dust, the Project Owner shall water or apply chemical dust suppressants to disturbed areas, apply gravel or paving to traffic areas, and wash wheels of vehicles or large trucks leaving the site. **MITIGATION:** ☑ The Project Owner shall prepare and implement a Fugitive Dust Mitigation Plan to minimize dust during construction. Condition: **AQ-C3 & AQ-C4.**		

<table>
<tr><th>Federal & California Air Quality Standards</th><th>PROJECT</th><th>CUMULATIVE IMPACTS</th><th>LORS COMPLIANCE</th></tr>
<tr><td rowspan="2">▪ Ozone (O3)</td><td>MITIGATION</td><td>None</td><td>YES</td></tr>
<tr><td colspan="3">
The power plant location is designated “moderate non-attainment” for state standard and “unclassified/attainment” for the federal ozone standards for ozone, which is primarily formed by chemical reactions between nitrogen oxides (NOx) and precursor organic compounds (VOC) in sunlight. Low-NOx combustors in the combustion turbine and Selective Catalytic Reduction (SCR) in the flue gas stack will minimize power plant emissions of NOx and VOCs as ozone precursors.
Since emissions would contribute to a violation of the ozone standards, the Project Owner shall obtain NOx and VOC offsets.
MITIGATION:
☑ The Project Owner shall use SCR to meet BACT emission limitations for NOX. Conditions: AQ-3, and AQ- 4, AQ-10, AQ-21.
☑ The Project Owner shall install a continuous emissions monitoring system for NOx and report emissions. Condition: AQ-12.
☑ The Project Owner shall limit NOx and VOC emissions. Conditions: AQ-4 through AQ- 7.
☑ The Project Owner shall obtain NOx and VOC offsets. Condition: AQ-18
</td></tr>
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▪ **Nitrogen Dioxide (NO2; also generically known as NOx)**	**MITIGATION**	**None**	**YES**
	MDAQMD is designated "attainment" for both the state and federal NO_2 ambient air quality standards. Project emissions would not create a violation of NO_2 standards. NO_2 is formed in the combustion process. Power plant NOx emissions will be minimized by low-NOx combustors in the combustion turbine plus SCR in the flue gas stack. For NO_2, the emission rate is limited to 2.0 ppm. NO_2 will be continuously monitored in the stack. NOx emissions would not cause a violation of NO_2 standards; however, NOx offsets are required as precursors to ozone. **MITIGATION:** ☑ The Project Owner shall use SCR to meet BACT emission limitations for NOx. Conditions: **AQ-3,** and **AQ- 4, AQ-10, AQ-21.** ☑ The Project Owner shall install a continuous emissions monitoring system for NOx and report emissions. Condition: **AQ-12**. ☑ The Project Owner shall limit NOx and VOC emissions. Conditions: **AQ-4** through **AQ- 7**. ☑ The Project Owner shall obtain NOx and VOC offsets. Condition: **AQ-18**		

	PROJECT	CUMULATIVE IMPACTS	LORS COMPLIANCE
▪ **Carbon Monoxide (CO)**	**MITIGATION**	**None**	**YES**
	The power plant location is designated attainment for federal and California CO. CO is formed in the combustion process. CO emissions, limited to 4 ppm, will be minimized by good combustion practices. If necessary, an oxidizing catalyst will be retrofitted in the HRSG. CO will be continuously monitored in the stack. **MITIGATION:** ☑ The Project Owner shall limit CO emissions. Conditions: **AQ-4** through **AQ-7.** ☑ The Project Owner shall install a continuous emissions monitoring system for CO. Condition: **AQ-12.** ☑ The Project Owner shall provide for the retrofit installation of an oxidation catalyst, if necessary. Condition: **AQ-28**.		
▪ **Particulate Matter 10 Microns (PM_{10})**	**MITIGATION**	**None**	**YES**
	The power plant location is designated *non-attainment* for state 24-hour PM_{10}. Primary PM_{10} is formed by the combustion gases in the exhaust stack. Secondary PM_{10} is formed downstream by mixed gases in the atmosphere. PM_{10} emissions will be monitored and limited. Since project PM_{10} emissions will contribute to an existing violation of air quality standards, offsets are required. **MITIGATION:** ☑ The Project Owner shall control PM_{10} to meet emission limitations. Condition: **AQ-4, AQ-6 & AQ-7**. ☑ The Project Owner shall obtain verifiable road paving PM_{10} offsets. Conditions**: AQ-C9 & AQ 18**.		

	PROJECT	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
▪ **Sulfur Dioxide (SO_2)**	**MITIGATION**	**None**	**YES**
	Sulfur Dioxide (SO_2) is produced from the combustion of fuels containing sulfur. The MDAQMD is designated "unclassified/attainment" for the federal SO_2 ambient air quality standards and "attainment" for the state SO_2 ambient air quality standards. The proposed project is using pipeline-quality natural gas, thus ensuring that sulfur emissions will be well within emission limits and not create violations of SO_2 standards. However, SO_2 emissions can contribute to the formation of secondary pollutants, such as secondary PM_{10}, thus contributing to a violation of the state PM_{10} standards. The Applicant has proposed to provide offsets for this potential contribution. **MITIGATION**: ☑ The Project Owner shall control SOx (as SO_2) to meet emission limitations. Conditions: **AQ-4, AQ-6 & AQ-7**. ☑ The Project Owner shall obtain SOx offsets as a precursor to secondary PM_{10} formation. Condition: **AQ-18**.		
▪ **Volatile Organic Compounds (VOC)**	**MITIGATION**	**None**	**YES**
	There are no state or federal standards for VOC, per se. VOCs are a precursor for ozone. (See ozone, above.) Consequently, limiting VOC emissions and the use of VOC offsets are part of the strategy for ozone attainment. VOCs are formed in the combustion process. BACT for VOC emissions will be achieved by use of good combustion practices, which use a fuel-to-air ratio resulting in low VOC emissions. If needed for controlling CO emissions, an oxidation catalyst further reduces VOC emissions. VOC offsets are required for ozone attainment. **MITIGATION:** ☑ The Project Owner shall control VOC to meet an emission limitation of 1.0 ppmvd. Conditions: **AQ-4, AQ-6 & AQ-7**. ☑ The Project Owner shall obtain VOC offsets, as a precursor to ozone. Conditions: **AQ-18.**		

	PROJECT	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Ammonia Slip	**CONDITION**	**None**	**YES**
	Significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia will mix with the flue gases to reduce NOx; a portion of the ammonia will pass through the SCR and will be emitted unaltered, out the stacks. These ammonia emissions are known as ammonia slip. The MDAQMD's FDOC requirement for ammonia slip is 10 ppm, 1-hour average. U.S. EPA, CARB, and Staff "strongly recommend" a limit of 5 ppm since additional ammonia control would be feasible and beneficial in reducing secondary PM_{10} formation. Instead, per the FDOC, the ammonia injection will be serviced if ammonia slip is consistently above 5 ppm averaged over 24 hours. **CONDITION:** ☑ The Project Owner shall replace, repair, or recondition the injection grid if ammonia slip begins consistently to exceed 5 ppm averaged over a 24-hour period. Condition: **AQ-C10**.		
Commissioning & Startup	**Insignificant**	**None**	**YES**
	The initial commissioning of a power plant refers to the time frame between completion of construction and the consistent production of electricity for sale to the market. Normal operating emission limits usually do not apply during initial commissioning procedures. The turbines will go through several series of tests during initial commissioning. Commissioning is a one-time event, subject to controls to minimize emissions. Therefore, there are no significant air quality impacts from facility commissioning. All startup scenarios result in emissions that are higher than normal operating emission limits; however, the number of startup events and their duration are controlled by District rules limiting daily and annual emissions. Thus, there is no significant air quality impact from facility startup.		

AIR QUALITY – GENERAL

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants due to the planned construction and operation of the project. Criteria air pollutants are defined as those for which a state or federal ambient air quality standard has been established to protect public health. They include nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), and particulate matter, both less than 10 microns in diameter (PM_{10}) and less than 2.5 microns ($PM_{2.5}$). Volatile organic compounds (VOCs) are regulated as precursors to ozone.

In carrying out this analysis, the Energy Commission evaluated the following major points:

- whether the project conforms with applicable Federal, State and local air quality laws, ordinances, regulations and standards;
- whether the project will cause significant air quality impacts, including a new violation of ambient air quality standards or contribution to existing violations of those standards; and
- whether the mitigation proposed for the project is adequate to lessen the potential impacts to a level of insignificance.

The Mojave Desert Air Quality Management District (MDAQMD) released its Final Determination of Compliance (FDOC) May 3, 2004. The MDAQMD informed the Commission that BACT levels for NOx and CO had been lowered as a result of the analysis performed in the Magnolia Power Project proceeding. (01-AFC-6). These revised BACT levels are now reflected in the Conditions of Certification. Project equipment includes Siemens Westinghouse V84.3A F-Class combustion turbine generators (natural gas fired) with dry, low NOx combustors; heat recovery steam generators (HRSG) with natural gas duct burners; and a selective catalytic reduction (SCR) system and, if necessary, a retrofit CO oxidizing catalyst system. A refrigerant-based inlet air chiller system will cool inlet air for added performance.

Construction Equipment/Fugitive Dust

The power plant construction requires the use of large earth moving equipment, which generates considerable combustion emissions, along with creating fugitive dust emissions during grading, site preparation, foundations, underground utility installation, and building erection.

The Applicant performed a modeling analysis of the potential construction impacts at the project site. Both the Applicant and the Energy Commission Staff (Staff) agreed that any construction impacts would be mitigated to the extent feasible by "boilerplate" construction Conditions of Certification. The boilerplate construction Conditions of Certification were derived from previously certified large and lengthy construction projects.

Construction of the project and ancillary facilities will result in unavoidable short-term impacts and it is likely that the general public may be exposed to construction impacts associated with the project. As indicated in Staff's FSA Air Quality Table 10, the project construction activities would further exacerbate existing violations of the state PM_{10} standards, and thus constitute a significant air quality impact for PM_{10}. Additionally, NOx and VOC emissions from construction equipment would react to contribute to existing violations of the ozone standards and thus would constitute a significant air quality impact for ozone via ozone precursors. The project's construction activities would not create a new violation of either NO_2, CO, or SO_2 air quality standards, thus impacts from NO_2, CO, and SO_2 emissions are not considered significant. (FSA, p. 4.1-21, 29)

The project will undertake one or more of the following measures to reduce emissions during construction activities (AFC, p. 7.7-54-55):

To control exhaust emissions from heavy diesel construction equipment:

- Limit engine idle time and shutdown equipment when not in use.
- Perform regular preventive maintenance to reduce engine problems.
- Use ultra-low sulfur fuel for all heavy construction equipment.
- Ensure that all heavy construction equipment complies with California Off-road Diesel Emission standards.
- Use catalyzed diesel particulate filters on diesel engines.

To control fugitive dust emissions:

- Use water application or chemical dust suppressant on unpaved travel surfaces and parking areas.
- Use wetting or covering of stored earth materials on-site.
- Require all trucks hauling loose material to either cover or maintain a minimum of two feet of freeboard.
- Use gravel pads and wheel washers as needed.
- Use windbreaks and chemical dust suppressant or water application to control wind erosion from disturbed areas.

The effectiveness of proposed mitigation for construction equipment emissions also depends largely on the vigilance of construction personnel to operate equipment properly. If the mitigation measures for fugitive dust-generating activities are applied correctly and with sufficient frequency, the control efficiency can approach 100 percent. The effectiveness of the mitigation measures depends upon the vigilance of construction personnel.

With monthly reporting and monitoring of certain environmental parameters to maintain a high degree of day-to-day vigilance, the foregoing measures would reduce potential PM_{10} and ozone impacts from the construction of BEP II to a level of insignificance. (FSA, p. 4.1-33)

MITIGATION:

☑ The Project Owner shall require construction contractors to mitigate diesel emissions by measures such as the use of ultra-low sulfur diesel fuel, and use of engines meeting

California Off-road Diesel Emission standards or use of catalyzed diesel particulate filters. Condition **AQ-C5**.

- ☑ The Project Owner shall prepare and implement a Fugitive Dust Mitigation Plan to minimize dust during construction. Conditions: **AQ-C3 & AQ-C4.**

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 air pollutants. Nitrogen oxides (NOx) and hydrocarbons (Volatile Organic Compounds (VOCs)) interact in the presence of sunlight to form ozone. The MDAQMD is designated "moderate non-attainment" for state standard and "unclassified/attainment" for the federal ozone standards. Controlling the ozone precursors, NO_2 and VOC, is the attainment strategy for attaining the federal ozone ambient air quality standard.

A network of monitoring stations normally determines local ambient air quality conditions; however, there are few stations near Blythe. The original BEP I modeling analysis used Twentynine Palms monitoring data for estimated ambient background concentrations. The Twentynine Palms monitoring station is located approximately 90 miles west-northwest of the project site, and indicates violations of the state 24-hour PM_{10} standard and both the state and federal 1-hour ozone standard. Twentynine Palms is downwind of industrial and urban areas, particularly Victorville and Barstow and to a certain extent, the Los Angeles Basin. Conversely, there are very few sources of industrial pollutants near Blythe. Therefore, it is likely that ozone concentrations in the Blythe area are lower than those measured at Twentynine Palms.

An analysis of the trend of ambient ozone concentrations around Blythe concluded that the air quality in Blythe is better than or equal to 1992 air quality, the last year for which Blythe area data are available.

No information on ozone concentrations in the Blythe area is available from the Arizona Department of Environmental Quality (ADEQ). The ADEQ does operate an ozone monitoring station in Yuma, approximately 90 miles south of Blythe along the Colorado River. For the year 2000, maximum ozone concentrations in Yuma were below the Twentynine Palms concentrations. The maximum monitored ozone concentrations in Yuma were 0.077 ppm (1-hour) and 0.068 ppm (8-hour) (ADEQ 2001). These concentrations are below the most restrictive CAAQS and NAAQS. (FSA, p. 4.1-8)

Ozone reduction requires reducing NOx and VOC emissions. To reduce NOx emissions, the Applicant proposes to use dry, low-NOx combustors in the combustion turbines and a post-combustion SCR system. To reduce VOC (and CO) emissions, the Applicant proposes to use advanced combustion control to achieve CO limits. The Applicant proposed to design the HRSG to allow a retrofitted installation of an oxidation catalyst in the event that combustion control could not meet the limits established by the permitting process. (FSA, p. 4.1-14, 15)

A NOx limit of 2.0 ppm is currently considered BACT for natural gas firing by both the EPA and the California Air Resources Board. Based upon manufacturer's data and a cost effectiveness analysis, MDAQMD specified a 3-hour average limit of 2.0 ppm. The MDAQMD established a CO limit of 4.0 ppmvd (24-hour average), except for startup, shutdown, and malfunction and VOC limit of 1 ppmvd (1-hour average). (FSA 4.1-14, 26)

In addition to emission control strategies included in the project design, the Applicant would provide emission reductions to offset emissions of ozone precursor pollutants (NOx 202 tpy and VOC 49 tpy). The Applicant is required to offset these pollutants by MDAQMD Regulation XIII by obtaining and surrendering sufficient valid emission reduction credits (ERCs). (FSA, p. 4.1-26)

MITIGATION:

- ☑ The Project Owner shall use SCR to meet BACT emission limitations for NOx. Conditions: **AQ-3,** and **AQ- 4, AQ-10, AQ-21.**
- ☑ The Project Owner shall install a continuous emissions monitoring system for NOx and report emissions. Condition: **AQ-12**.
- ☑ The Project Owner shall limit NOx and VOC emissions. Conditions: **AQ-4** through **AQ- 7**.
- ☑ The Project Owner shall obtain NOx and VOC offsets. Condition: **AQ-18**

__Nitrogen Dioxide__

Nitrogen dioxide (NO_2) can be emitted directly as a result of combustion or can be formed from nitric oxide (NO) and oxygen. NO is typically emitted from combustion sources and readily reacts with oxygen or ozone to form NO_2. The NO reaction with ozone can occur within minutes and is typically referred to as ozone scavenging. By contrast, the NO reaction time with oxygen is on the order of hours under the proper conditions. MDAQMD is designated “attainment” for both the state and federal NO_2 ambient air quality standards. (FSA, p. 4.1-9) Project emissions would not create a violation of NO_2 standards. (FSA, p. 4.1-22).

The combustion turbines would limit NOx formed during combustion using dry low-NOx combustors. Compared to steam or water-injection designs, combustors designed for dry low-NOx firing maintain low temperatures, thus minimizing NOx formation, while thermal efficiencies remain high.

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, a flue gas control system, including a catalyst system, will be installed in the HRSG. The Applicant is proposing a selective catalytic reduction system to reduce NOx. The project owner has proposed all practical and technically feasible mitigation measures to limit NOx emissions from the combustion turbines to 2.0 ppm.

MITIGATION:

- ☑ The Project Owner shall use SCR to meet BACT emission limitations for NOx. Conditions: **AQ-3,** and **AQ- 4, AQ-10, AQ-21**

- ☑ The Project Owner shall install a continuous emissions monitoring system for NOx and report emissions. Condition: **AQ-12**.
- ☑ The Project Owner shall limit NOx emissions. Conditions: **AQ-4** through **AQ- 7**.
- ☑ The Project Owner shall obtain NOx offsets. Condition: **AQ-18**

<u>Carbon Monoxide</u>

Carbon monoxide (CO) is a directly emitted air pollutant as a result of combustion. The MDAQMD is designated "unclassified/attainment" for the federal 1-hour and 8-hour CO ambient air quality standards and "unclassified" for the state standards. Project emissions would not create a violation of CO standards. (FSA, p. 4.2-22)

<u>Oxidizing Catalyst</u>
Through the use of advanced combustion control, the Applicant proposed to achieve CO concentrations of less than 5 ppmvd or 8.4 ppmvd, depending on the CTG load. However, a more stringent 4.0 ppmvd CO limit (based on a 24-hour average) is established by the FDOC, except during periods of startup, shutdown and malfunction.

The Applicant investigated using an oxidizing catalyst system to reduce CO, but determined that it would not be cost effective and instead proposes to manage these pollutants by controlling the combustion process.

The Applicant proposed to design the HRSG to allow a retrofitted installation of an oxidation catalyst in the event that combustion control could not meet the limits established by the FDOC. (FSA, p. 4.1-14, 26; AFC p. 7.7-36)

MITIGATION:
- ☑ The Project Owner shall limit CO emissions. Conditions: **AQ-4** through **AQ-7.**
- ☑ The Project Owner shall install a continuous emissions monitoring system for CO. Condition: **AQ-12.**
- ☑ The Project Owner shall provide for the retrofit installation of an oxidation catalyst, if necessary. Condition: **AQ-28**.

<u>Particulate Matter – PM_{10}</u>
PM_{10} is a particulate that is 10 microns in diameter or smaller and is suspended in air. PM_{10} can be directly emitted from a combustion source (primary PM_{10}), soil disturbance (fugitive dust) or it can form miles downwind (secondary PM_{10}) from some of the constituents of combustion exhaust (NOx, SOx and ammonia). Secondary particulates are probably a minor fraction of the overall PM_{10} concentrations in the project area because there are few major sources of precursors. In the desert, wind blown dust contributes to elevated PM_{10} concentrations. This means that the make-up of ambient particulate matter in the project area on the days of highest concentrations is largely of a geologic or mineral nature. (FSA, p. 4.1-10, 11)

The MDAQMD has been designated an "unclassified/attainment" zone for the *federal* 24-hour and annual PM_{10} ambient air quality standards. The less-stringent federal standards have not recently been violated by ambient PM_{10} concentrations. Historic violations of federal PM_{10} standards in the Mojave Desert Planning Area (San Bernardino County) led the MDAQMD to prepare a PM_{10} attainment plan in 1995. The plan attributed the violations to a heavy concentration of fugitive dust sources near the urbanized areas and large-scale high wind events. Public unpaved roads were identified as a significant category of dust emissions in the planning area warranting control (MDAQMD 1995).

The MDAQMD has been designated as a "non-attainment" zone for the *state* 24-hour and annual PM_{10} ambient air quality standards. Emissions of primary PM_{10} are reduced by the use of natural gas as the power plant fuel. Natural gas contains very little solid particulate.

Fine Particulate Matter - $PM_{2.5}$

The U.S. EPA first identified ambient air quality standards for fine particulate matter ($PM_{2.5}$) in 1997, and most $PM_{2.5}$ ambient air quality monitors began delivering information around 2000. The MDAQMD does not need to develop an air quality management plan for $PM_{2.5}$ because the Mojave Desert Air Basin was designated in 2004 as an area that is either unclassified or attains both the state and federal $PM_{2.5}$ standards.

Preliminary data is available for $PM_{2.5}$ from monitoring stations in Victorville starting in 1999. The maximum 24-hour concentration occurring between 1999 and 2003 was 38.0 $\mu g/m^3$. Compared to the 1997 U.S. EPA standard of 65 $\mu g/m^3$, this area would not exceed the federal standard. The highest annual average concentration for 1999 through 2003 was 13.9 $\mu g/m^3$. Compared to the 1997 U.S. EPA standard of 15 $\mu g/m^3$, this area would not exceed the federal standard. Since a three-year data record of concentrations exceeding the standard is necessary to qualify for non-attainment status, the Mojave Desert is an attainment area despite having one year of recent data exceeding the state standard of 12 $\mu g/m^3$.

Concentrations of PM_{10} and $PM_{2.5}$ in the Mojave Desert are weakly seasonal, with higher $PM_{2.5}$ concentrations normally occurring in the winter. High PM_{10} concentrations from wind blown dust can occur during any time of the year. Managing $PM_{2.5}$ concentrations will require the MDAQMD to identify controllable sources and develop feasible source management strategies. Since PM_{10} includes $PM_{2.5}$ as a subset and reactive precursors that lead to ozone can also lead to $PM_{2.5}$, the established strategies for controlling PM_{10} and ozone precursors (including existing programs for combustion sources) should help to reduce $PM_{2.5}$ concentrations.

The exclusive use of pipeline-quality natural gas, a relatively clean-burning fuel, will limit emissions of PM_{10} (and SO_2). Natural gas contains very little noncombustible gas or solid residues and a small amount of reduced sulfur compounds, thus resulting in relatively low emissions of PM_{10} and SO_2. The Applicant anticipates that the supplied natural gas will contain less than 0.5 grains of sulfur per 100 dry standard cubic feet (dscf), which is less than the 1 grain per 100 scf recommended by CARB (AFC p. 7.7-38; FSA 4.1-11, 12).

Cooling Tower Drift

The BEP II cooling tower will be equipped with mist eliminators guaranteed by the manufacturer to limit drift to 0.0006 percent. The Applicant proposes a total dissolved solids (TDS) limit of 8,190 mg/l, and a maximum water circulation rate of 146,000 gpm for the cooling tower (AFC p. 7.7-38). The inlet air chiller will include a cooling tower equipped with mist eliminators that would reduce drift to 0.001 percent. .

The cooling tower may also cause emissions of small quantities of organic chemicals, if organic compounds are identified in project wells. (FSA, p. 4.1-15)

Fugitive Dust

The Water Conservation Offset Program (WCOP) that the Applicant proposes to offset groundwater use would result in rotational fallowing or permanent retirement of agricultural land in the area. Agricultural operations currently cause emissions of farm equipment exhaust and fugitive dust from tilling, planting, fertilizing, and harvesting, which contribute to elevated PM_{10} concentrations. According to the Applicant's proposal, each landowner that participates in the rotational fallowing program would be required to implement erosion control practices, and participation in the WCOP would require implementation of clod forming processes consistent with federal guidelines. Thus, monitored implementation of the WCOP is not expected to result in any significant net fugitive dust emission changes. (FSA, p. 4.1-15)

Offsets

The modeling results indicate that the project's operational impacts could further exacerbate existing violations of the state PM_{10} standard. In light of the existing state PM_{10} non-attainment status for the region, the impacts of direct PM_{10} emissions are considered to be significant and warrant additional mitigation.

There is also a potential for $PM_{2.5}$ impacts to occur because the project would also emit this contaminant and precursors. The magnitude of potential $PM_{2.5}$ impacts is not quantified here because there is not an established methodology for quantifying $PM_{2.5}$ emissions from every source and because there is no established method for characterizing the complex interaction of $PM_{2.5}$ precursors in the ambient air. Mitigating combustion-related PM_{10}, which includes $PM_{2.5}$, and mitigating reactive precursor emissions that can lead to $PM_{2.5}$ could provide $PM_{2.5}$ mitigation. The best available information indicates that ambient concentrations of $PM_{2.5}$ probably do not exceed either the state or federal air quality standards. Based on the levels of PM_{10} and $PM_{2.5}$ precursor impacts, routine operation of the project is not expected to create any new violations of $PM_{2.5}$ impacts. (FSA, p. 4.1-22)

As identified above, PM_{10} impacts would be significant due to direct emissions. Secondary impacts (from NOx, SOx and ammonia emissions) would be significant for PM_{10} and ozone because routine operational emissions of precursor pollutants would contribute to existing violations of the state-level PM_{10} and ozone standards (FSA AIR QUALITY Table 3). Along with mitigation that is appropriate to reduce potentially significant, direct impacts of PM_{10}, additional mitigation for emissions of precursors is appropriate to reduce secondary impacts to PM_{10} and ozone.

Thus, in addition to emission control strategies included in the project design, the Applicant would provide emission reductions to offset emissions of PM_{10}, SOx, and ozone precursor pollutants (NOx and VOC). The Applicant is required to offset these pollutants by MDAQMD Regulation XIII by obtaining and surrendering sufficient valid emission reduction credits (ERCs).

The PM_{10} ERCs would come from the Colorado River Indian Tribe (CRIT), which agreed to allow the Applicant to pave Lost Lake Road, Colorado River Road, and Roadrunner Alley. Approximately 9,280 linear feet (1.75 miles) of total roadways were identified by the agreement. The MDAQMD indicates that 126 tpy of PM_{10} offsets will be obtained by the Applicant through this agreement. This level of emission reduction is based on the use of outdated emission factors from the U.S. EPA. U.S. EPA made more recent guidance available in December 2003, but the MDAQMD intends to follow the methodology that was in place at the time of the Applicant's original proposal for BEPII in 2002.

Energy Commission staff believes that the application for the CRIT road paving ERC should follow the more recent calculation method, which would result in a diminished ERC value of approximately 70 tpy, not 126 tpy. Staff believes paving additional CRIT roads could probably make up the difference in offsets. (FSA, p. 4.1-27, 28)

In addition, Staff has reservations about using dust control to mitigate impacts from combustion-related particulate matter. The effectiveness of paving dirt roads depends on whether the credits are real, enforceable, surplus, permanent, and quantifiable. Fugitive dust from unpaved public roads is not a source category that is normally subject to permitting in the MDAQMD. However, MDAQMD supports use of road paving PM_{10} reductions as a means of offsetting the PM_{10} from natural gas combustion and has used road paving as a source of ERCs for earlier projects (including BEP I).

The roads proposed for paving by the Applicant and CRIT would probably not otherwise be paved in the future because they are on tribal land. The California Air Resources Board (CARB) also previously expressed specific concerns about using road paving offsets for combustion sources. CARB noted that combustion of natural gas emits very fine particulate matter less than 2.5 microns in size ($PM_{2.5}$), and dust control from road paving provides reduction of particles much larger in size, the majority PM_{10}, with only 13 to 15 percent of the emission reductions being less than 2.5 microns. In other siting cases, Staff has recommended correcting the ERC for PM_{10}-to-$PM_{2.5}$ effectiveness because only about 15 percent of the PM_{10} reduction would qualify as $PM_{2.5}$. Staff's analysis of BEP II impacts reveals that the project would not be likely to cause new $PM_{2.5}$ violations or contribute to $PM_{2.5}$ violations, because there is no evidence of a $PM_{2.5}$ attainment problem in the setting. The $PM_{2.5}$ effectiveness of the road paving ERC is less important in this setting, and the PM_{10} reductions achieved by road paving would be suitable for mitigating the PM_{10} impacts of the project. (FSA, p. 4.1-30, 31)

The U.S. EPA originally indicated that the road paving ERCs would be invalid and that the MDAQMD must require the Applicant to obtain different PM_{10} ERCs. U.S. EPA also noted that the Applicant must be required to provide public notice of valid ERCs before issuing the FDOC. However, no alternative ERCs have been identified, and the proposed ERCs from

CRIT have not been subject to any public notice, as required by Rule 1402(B). It is now clear that the MDAQMD supports the use of road paving and that compliance with MDAQMD Regulation XIII would be satisfied without the need for alternative ERCs. The U.S. EPA has offered no further comments. (FSA, p. 4.1-28)

When the proposed offsets are taken together in the ambient setting, Staff accepts that the project's emissions of PM_{10} would be fully mitigated by the proposed road paving offsets. To ensure full mitigation of PM_{10} and ozone impacts with the proposed ERCs, Staff recommends a condition (**AQ-C9**) to assure that the proposed offsets will be acquired. (FSA, p. 4.1-33)

MITIGATION:

- ☑ The Project Owner shall control PM_{10} to meet emission limitations. Condition: **AQ-4, AQ-6 & AQ-7**.
- ☑ The Project Owner shall obtain verifiable road paving PM_{10} offsets. Conditions**: AQ-C9 & AQ 18**.

Sulfur Dioxide

Sulfur dioxide is typically emitted as a result of the combustion of fuel containing sulfur. Fuels such as natural gas contain very little sulfur and consequently have very low SO_2 emission when combusted. The MDAQMD is designated "unclassified/attainment" for the federal SO_2 ambient air quality standards and "attainment" for the state SO_2 ambient air quality standards.

The modeling results indicate that the project's operational impacts would not create violations of SO_2 standards. (FSA 4.1-22) However, SO_2 emissions can contribute to the formation of secondary pollutants, such as secondary PM_{10}, thus contributing to a violation of the state PM_{10} standards. The Applicant has proposed to provide offsets for this potential contribution. (FSA, p. 4.1-29, 31)

MITIGATION:

- ☑ The Project Owner shall control SOx (as SO_2) to meet emission limitations. Conditions: **AQ-4, AQ-6 & AQ-7**.
- ☑ The Project Owner shall obtain SOx offsets as a precursor to secondary PM_{10} formation. Condition: **AQ-18**.

Volatile Organic Compounds

There are no state or federal ambient air quality standards for Volatile Organic Compounds (VOC). VOCs are a precursor for ozone. Consequently, the MDAQMD limits VOC emissions and uses VOC offsets as part of the strategy for ozone attainment. VOCs are formed in the combustion process. BACT for VOC emissions (1 ppmvd) will be achieved by use of good combustion practices, which use a fuel to air ratio resulting in low VOC emissions. If needed to comply with CO emissions limits, an oxidation catalyst further reduces VOC emissions. The Applicant will obtain VOC offsets as part of the ozone attainment strategy. (NOx offsets may be substituted for VOC offsets for ozone attainment.) (FSA, p. 4.1-14, 32)

MITIGATION:

- ☑ The Project Owner shall control VOC to meet an emission limitation of 1.0 ppmvd. Conditions: **AQ-4, AQ-6 & AQ-7**.
- ☑ The Project Owner shall obtain VOC offsets, as a precursor to ozone. Conditions: **AQ-18.**

Ammonia Emissions

Due to the large combustion turbines used in this project and the need to control NOx emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia will mix with the flue gases to reduce NOx; a portion of the ammonia will pass through the SCR and will be emitted, unaltered, out the stacks. These ammonia emissions are known as ammonia slip. The Applicant has proposed achieving an ammonia slip no greater than 10 ppm. Staff and the Applicant anticipate that ammonia slip levels well below 5 ppm would be achievable especially early in the catalyst life. The Applicant expects a catalyst life of approximately five years, depending on operating conditions. (FSA, p. 4.1-18)

The MDAQMD's FDOC requirement for ammonia slip is 10 ppm, and so differs from comments to MDAQMD from U.S. EPA which "strongly recommend" a limit of 5 ppm for BEP II and guidance from CARB. These agencies indicate that the more-stringent ammonia slip level of 5 ppm is achievable, and Energy Commission staff agrees. The 10 ppm limit in the FDOC would satisfy the MDAQMD requirements. While Staff believes that additional ammonia control would be feasible and appropriate given the potential for secondary PM_{10} formation, Staff agrees that ammonia slip shall not exceed 10 ppm averaged over a one-hour period. However, if ammonia slip begins consistently to exceed 5 ppm averaged over a 24-hour period, the Applicant will replace, repair, or recondition the injection grid within 12 months. See Condition: **AQ-C-10**. (FSA, p. 4.1-29, 44)

CONDITION:

- ☑ The Project Owner shall replace, repair, or recondition the injection grid if ammonia slip begins consistently to exceed 5 ppm averaged over a 24-hour period. Condition: **AQ-C-10**.

Commissioning and Start-Up

The initial commissioning of a power plant refers to the time frame between completion of construction and the consistent production of electricity for sale on the market. Normal operating emission limits usually do not apply during initial commissioning procedures. The turbines used at BEPII will go through several series of testing during initial commissioning. During the first set of tests, post-combustion controls will not be operational (i.e., the SCR).

The Applicant identified the series of tests (AFC Appendix 7.7-N) that would result in greater-than-routine emissions as each unit is commissioned. These tests would require approximately 300 hours of operations over approximately a two- to four-month period. Emissions of all pollutants other than NOx and CO would be similar during commissioning to those that would occur under routine conditions. As such, the impacts analysis for initial commissioning only considers NOx and CO for short-term periods. Emissions occurring during the commissioning would accrue toward the annual limitations imposed by the MDAQMD. (FSA, p. 4.1-19)

BEP II has three general start-up scenarios: cold start, warm start, and hot start. Cold startups usually occur after extended periods of shutdown, typically 3 days or more. Warm startups occur after shorter periods of shutdown duration than those for cold startups, from 24 to 72 hours. Hot startups generally occur following a trip off line or non-critical emergency shutdown, usually lasting only a few hours. Except for CO emissions, the project owner has chosen to assume that hot and warm startups emissions are the same as cold startup emissions. The project owner assumes 365 hours of startups per year per turbine. The Energy Commission does not propose to place a limit on the number or type of startups each day or year, since the daily and annual emission limits serve as a practical constraint. (FSA, p. 4.1-17)

PSD Review

PSD regulations apply to the preconstruction review of stationary sources that emit attainment air contaminants. In the MDAQMD, the PSD program is implemented by the U.S. EPA, and BEP II originally applied for a PSD permit in 2002. Because this federal permitting process is ongoing, and there remains a possibility of revised conditions, staff recommends a condition to ensure that future possible modifications will be coordinated. See Condition: AQ-C6. (FDOC p. 36.)

Cumulative Impacts

To evaluate reasonably foreseeable future impacts as part of the project impacts analysis, the Applicant performed a cumulative modeling analysis. The cumulative analysis included potential and/or permitted, but not yet operating, projects located up to six miles from the proposed facility site. The Applicant consulted MDAQMD to identify potential and/or permitted projects of a size that might interact with the Applicant project plumes and impacts. None was identified, so additional analysis and cumulative modeling were not conducted.

FINDING

With the implementation of the Conditions of Certification, below, the project conforms with applicable laws related to air quality, and all potential adverse impacts to air quality will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

AQ-C1 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 **AQ-C3**, **AQ-C4** and **AQ-C5** 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 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. The AQCMM and all Delegates must be approved by the CPM before the start of ground disturbance.

AQ-C2 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 **AQ-C3**, **AQ-C4** and **AQ-C5**.

<u>**Verification:**</u> 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 CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt.

AQ-C3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report (MCR) 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 **AQ-C4** (the prevention of fugitive dust plumes). 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) The construction site entrances shall be posted with visible speed limit signs.
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 CPM.

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 as necessary on days when construction activity occurs to prevent the accumulation of dirt and debris.

j) At least the first 500 feet of any public roadway exiting from the construction site shall be swept as necessary on days when construction activity occurs or on any other day when dirt or runoff from the construction site is visible on the public 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 project owner shall include in the MCR (1) a summary of all actions taken to maintain compliance with this condition, (2) copies of any complaints filed with the air district in relation to project construction, and (3) 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-C4 Dust Plume Response Requirement: The AQCMM or an AQCMM Delegate shall continuously monitor the 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 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 eliminate visible dust plumes at any location 200 feet or more off the project site within one hour of the original determination. The activity shall not restart until the AQCMM or Delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or Delegate to shut down an activity, provided that the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified.

AQ-C5 Diesel-Fueled Engines Control: The AQCMM shall submit to the CPM, in the Monthly Compliance Report (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) All construction diesel engines, which have a rating of 100 hp or more, shall meet, at a minimum, the Tier 1 California Emission Standards for Off-Road Compression-Ignition Engines as specified in California Code of Regulations, Title 13, section 2423(b)(1) unless certified by the on-site AQCMM that such engine is not available for a particular item of equipment. In the event a Tier 1 engine is not available for any off-road engine larger than 100 hp, that engine shall be equipped with a catalyzed diesel particulate filter (soot filter), unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is "not practical" if, among other reasons:

   (1) There is no available soot filter that has been certified by either the California Air Resources Board or U.S. Environmental Protection Agency for the engine in question; or

   (2) The construction equipment is intended to be on-site for ten (10) days or less.

   (3) The CPM may grant relief from this requirement if the AQCMM can demonstrate that they have made a good faith effort to comply with this requirement and that compliance is not possible.

d) The use of a soot filter may be terminated immediately if one of the following conditions exists, provided that the CPM is informed within ten (10) working days of the termination:
   (1) The use of the soot filter is excessively reducing normal availability of the construction equipment due to increased downtime for maintenance, and/or reduced power output due to an excessive increase in backpressure.
   (2) The soot filter is causing or is reasonably expected to cause significant engine damage.
   (3) The soot filter is causing or is reasonably expected to cause a significant risk to workers or the public.
   (4) Any other seriously detrimental cause which has the approval of the CPM prior to the termination being implemented.

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 heavy construction equipment with engines meeting the requirements of (n)(3) above shall not remain running at idle for more than five minutes, to the extent practical.

<u>Verification:</u> The project owner shall include in the MCR (1) a summary of all actions taken to maintain compliance with this condition, (2) copies of all diesel fuel purchase records, (3) 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 (4) 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-C6 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. EPA, and any revised permit issued by the District or U.S. EPA for the project.

<u>Verification:</u> The project owner shall submit any 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.

QUARTERLY OPERATIONS REPORT

AQ-C7 The project owner shall submit Quarterly Operational Reports to the CPM and District that include operational and emissions information as necessary to demonstrate compliance with Conditions **AQ-C10** and **AQ-C11**, and **AQ-1** through **AQ-54**, as applicable. The Quarterly Operational Report will specifically note or highlight instances of noncompliance and the corrective measures taken to correct these incidents.

Verification: The project owner shall submit the Quarterly Operational Reports to the CPM and the District no later than 30 days following the end of each calendar quarter.

AMENDING AIR QUALITY CONDITIONS OF CERTIFICATION

AQ-C8 The CPM, in consultation with the District, may approve any change to a Condition of Certification regarding air quality, as an insignificant change, provided that: (1) the project remains in compliance with all applicable laws, ordinances, regulations, and standards, (2) the requested change clearly will not cause the project to result in a significant environmental impact, (3) no additional mitigation or offsets will be required as a result of the change, (4) no existing daily, quarterly, or annual permit limit will be exceeded as a result of the change, and (5) no increase in any daily, quarterly, or annual permit limit will be necessary as a result of the change.

Verification: The project owner shall notify the CPM in writing of any proposed change to a condition of certification pursuant to this condition and shall provide the CPM with any additional information the CPM requests to substantiate the basis for approval.

AQ-C9 The project owner shall surrender the emission offset credits listed below or a modified list, as allowed by this condition, at the time that surrender is required by Condition **AQ-18**. The ERC list shall contain evidence that the MDAQMD and the U.S. EPA have determined that the ERCs are real, enforceable, surplus, permanent, and quantifiable. The project owner may request CPM approval for any substitutions or modification of credits listed below. The CPM, in consultation with the District and the U.S. EPA, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, the requested change(s) clearly will not cause the project to result in a significant environmental impact, and each requested change is consistent with applicable federal and state laws and regulations.

MDAQMD ERC Source	ERC Identification	NOx (tpy)	PM_{10} (tpy)	SOx (tpy)	VOC (tpy)
Colorado River Indian Tribe Road Paving - 3,000 ft Lost Lake Road - 5,280 ft Colorado River Road - 1,000 ft Roadrunner Alley - And additional road lengths as necessary to conform to the current version of U.S. EPA guidance document AP-42	MDAQMD (pending)	0	126	0	0
SoCal Gas Compressor Engines	MDAQMD – 0051	251	0	0	0

Note: MDAQMD allows interpollutant trading of NOx and PM_{10} ERCs to fully offset VOC and SOx, respectively.

Verification: The project owner shall submit to the CPM a list of ERCs to be surrendered to the District at least 60 days prior to construction. The list of ERC's shall include evidence that the U.S. EPA concurs with the determination that the ERCs are valid. If the CPM, in consultation with the District, approves a substitution or modification, the CPM shall file a statement of the approval with the commission docket and mail a copy of the statement to every person on the post-certification mailing list. The CPM shall maintain an updated list of approved ERCs for the project.

AQ-C10 The ammonia slip shall not exceed 10 ppmv @ 15 percent O_2 averaged over one hour. The SCR ammonia injection grid shall be replaced, repaired or otherwise reconditioned within 12 months of the ammonia slip reaching 5 ppm @ 15 percent O_2 averaged over 24 hours with the following provision. The SCR ammonia injection grid replacement, repair or reconditioning scheduled event shall be canceled if the project owner can demonstrate to the CPM that, subsequent to the initial exceedance, the ammonia slip is remaining below 5 ppm @ 15 percent O_2 averaged over 24 hours and that the initial exceedance was a false trigger.

Protocol: Compliance with ammonia slip limits shall be demonstrated by using the following calculation procedure:

ammonia slip ppmv @ 15% O_2 = ((a - (b x c/1,000,000)) x 1,000,000 / b) x d, where

- a = ammonia injection rate (lb/hr) /17 (lb/lb-mol),
- b = dry exhaust gas flow rate (lb/hr) /29 (lb/lb-mol),
- c = change in measured NOx concentration ppmv at 15% O_2 across catalyst, and
- d = correction factor.

The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip.

Verification: The project owner shall include ammonia slip concentrations averaged on an hourly and 24-hour basis calculated via the protocol provided as part of the Quarterly Operational Reports (**AQ-C7**). The project owner shall notify the CPM within 10 days of an exceedance of the 5-ppm ammonia slip limit herein. The project owner shall notify the CPM no less than 30 days prior to the scheduled date of the SCR ammonia injection grid replacement, repair, or reconditioning event. If the project owner finds that the exceedance of the 5-ppm ammonia slip limit was a “false trigger” as provided for in this condition, the project owner shall submit all relevant information to the CPM no less than 30 days prior to the scheduled date of the SCR ammonia injection grid replacement, repair or reconditioning event in order to cancel the event.

AQ-C11 If the project owner does not participate in the voluntary California Climate Action Registry, then the project owner shall report to the CPM the quantity of CO_2 emitted on an annual basis as a direct result of facility electricity production.

Verification: Any CO_2 emissions that are reported to the California Climate action Registry or pursuant to this condition shall be reported to the CPM as part of the fourth Quarterly Operational Reports (**AQ-C7**).

DISTRICT DETERMINATION OF COMPLIANCE CONDITIONS

<u>Turbine Power Train Conditions</u>

[Two (2) individual 1776 MMBtu/hr F Class Gas Turbine Generators; MDAQMD Permit Numbers: B008877 and B008878]

[Conditions AQ-1 through AQ-28 apply to each combustion turbine, unless otherwise specified.]

AQ-1 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

<u>Verification:</u> The project owner shall provide to the District and CPM, 30 days prior to installation of each combustion turbine, manufacturer and design data. A summary of significant operation and maintenance events for each combustion turbine shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-2 This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf on a rolling twelve month average basis, and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

<u>Verification:</u> The project owner shall provide in the Quarterly Operational Reports (**AQ-C7**) either a monthly laboratory analysis showing the fuel sulfur content, a monthly fuel sulfur content report from the fuel supplier(s), or the results from a custom fuel monitoring schedule approved by U.S. EPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG.

AQ-3 This equipment is subject to the federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and GG (Standards of Performance for Stationary Gas Turbines). This equipment is also subject to the Prevention of Significant Deterioration (40 CFR 51.166) and Federal Acid Rain (Title IV) programs. Compliance with all applicable provisions of these regulations is required.

<u>Verification:</u> At least ninety (90) days prior to the first firing of fuel in either turbine, the project owner shall provide the District, CARB and CPM with copies of the federal PSD and Acid Rain permits.

AQ-4 Emissions from this equipment (including its associated duct burner) shall not exceed the following emission limits at any firing rate, except for CO, NOx and VOC during periods of startup, shutdown and malfunction:

a. Hourly rate, computed every 15 minutes, verified by CEMS and annual compliance tests:
   i. NOx as NO2 – 14.82 lb/hr (based on 2.0 ppmvd corrected to 15% oxygen and averaged over three hours)
   ii. CO – 18.04 lb/hr (based on 4.0 ppmvd corrected to 15% oxygen and averaged over 24 hours)
b. Hourly rates, verified by annual compliance tests or other compliance methods in the case of SOx:
   i. VOC as CH4 – 2.90 lb/hr (based on 1 ppmvd corrected to 15% oxygen)
   ii. SOx as SO2 – 2.66 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)
   iii. PM_{10} – 6.0 lb/hr

<u>**Verification:**</u> The project owner shall submit the following in the Quarterly Operational Reports (**AQ-C7**): All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol; a list of maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NOx, CO, PM_{10}, VOC and SOx (including calculation protocol); and a log of all excess emissions, including the information regarding malfunctions/breakdowns required by District Rule 430. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip. Any maintenance to any air pollutant control system (recorded on an as-performed basis). Any permanent changes made in the plant process or production that could affect air pollutant emissions, and when the changes were made.

AQ-5 Emissions of CO and NOx from this equipment shall only exceed the limits contained in Condition **AQ-4** during startup and shutdown periods as follows:

a. Startup is defined as the period beginning with ignition and lasting until either the equipment complies with all operating permit limits specified in Condition AQ-4a for two consecutive 15-minute averaging periods or four hours after ignition, whichever occurs first. Shutdown is defined as the period beginning with the lowering of equipment from base load and lasting until fuel flow is completely off and combustion has ceased.
b. The emissions from each startup or shutdown event shall not exceed the following, verified by CEMS:
   i. NOx – 376 lb
   ii. CO –3600 lb

<u>**Verification:**</u> The project owner shall include a detailed record of each startup and shutdown event in the Quarterly Operational Reports (**AQ-C7**). Each record shall include, but not be limited to, duration, fuel consumption, total emissions of NOx and CO, and the date and time of the beginning and end of each startup and shutdown event. Additionally, the project owner shall report the total plant operation time (hours), number of startups, hours in cold startup,

hours in warm startup, hours in hot startup, hours in shutdown, and average plant operation schedule (hours per day, days per week, weeks per year).

AQ-6 Emissions from this facility, including the duct burners and cooling towers, shall not exceed the following emission limits, based on a calendar day summary:

a. NOx – 2924 lb/day, verified by CEMS
b. CO – 17,016 lb/day, verified by CEMS
c. VOC as CH4 – 187 lb/day, verified by compliance tests and hours of operation in mode
d. SOx as SO2 – 128 lb/day, verified by fuel sulfur content and fuel use data
e. PM_{10} – 336 lb/day, verified by compliance tests and hours of operation

Verification: The project owner shall submit in the Quarterly Operational Reports (**AQ-C7**) the information required by **AQ-4** and a calendar day summary of emissions demonstrating compliance with these limits.

AQ-7 Emissions from this facility, including the duct burners and cooling towers, shall not exceed the following emission limits, based on a rolling 12 month summary:

a. NOx – 202 tons/year, verified by CEMS
b. CO – 685 tons/year, verified by CEMS
c. VOC as CH4 – 25 tons/year, verified by compliance tests and hours of operation in mode
d. SOx as SO2 – 23 tons/year, verified by fuel sulfur content and fuel use data
e. PM_{10} – 61 tons/year, verified by compliance tests and hours of operation

Verification: The project owner shall submit in the Quarterly Operational Reports (**AQ-C7**) the information required by **AQ-4** and a rolling 12 month summary of emissions demonstrating compliance with these limits.

AQ-8 Particulate emissions from this equipment shall not exceed an opacity equal to or greater than twenty percent (20%) for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and Commission upon request.

AQ-9 This equipment shall exhaust through a stack at a minimum height of 130 feet.

Verification: Prior to the first firing of natural gas in either turbine the project owner shall provide to the District and the CPM as-built drawings of the stack or other suitable proof of the minimum stack height.

AQ-10 The project owner shall not operate this equipment after the initial commissioning period without the selective catalytic NOx reduction system with valid District permit # C008881 or C008882 installed and fully functional.

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

AQ-11 The project owner shall provide stack sampling ports and platforms necessary to perform source tests required to verify compliance with District rules, regulations and permit conditions. The location of these ports and platforms shall be subject to District approval.

<u>Verification:</u> Prior to the first firing of natural gas in either turbine the project owner shall provide to the District and the CPM as-built drawings of the stack or other suitable documentation of the correct and complete installation of all necessary sampling ports and access platforms.

AQ-12 Emissions of NOx, CO, oxygen and ammonia slip shall be monitored using a Continuous Emissions Monitoring System (CEMS). Turbine fuel consumption shall be monitored using a continuous monitoring system. Stack gas flow rate shall be monitored using either a Continuous Emission Rate Monitoring System (CERMS) meeting the requirements of 40 CFR 75 Appendix A or a stack flow rate calculation method. The project owner shall install, calibrate, maintain, and operate these monitoring systems according to a District-approved monitoring plan and MDAQMD Rule 218, and they shall be installed prior to initial equipment startup.

<u>Verification:</u> Six (6) months prior to monitoring system installation, the project owner shall submit a monitoring plan for District review and approval. The project owner shall provide the CPM documentation of the District's approval of the CEMS, continuous fuel monitoring system, and CERMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.

AQ-13 The project owner shall conduct all required compliance/certification tests in accordance with a District-approved test plan.

<u>Verification:</u> Thirty (30) days prior to the compliance/certification tests the project owner shall provide a written test plan for District review and approval. The project owner shall provide the CPM documentation of the District's approval of the test plan within 15 days of its receipt. Written notice of the compliance/certification test shall be provided to the District and CPM ten (10) days prior to the tests so that an observer may be present. A written report with the results of such compliance/certification tests shall be submitted to the District and CPM within forty-five (45) days after testing.

AQ-14 The project owner shall perform the following annual compliance tests in accordance with the MDAQMD Compliance Test Procedural Manual. The following compliance tests are required:

a. NOx as NO2 in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Methods 19 and 20).
b. VOC as CH4 in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Methods 25A and 18).
c. SOx as SO2 in ppmvd at 15% oxygen and lb/hr.
d. CO in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Method 10).
e. PM_{10} in mg/m3 at 15% oxygen and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).
f. Flue gas flow rate in DSCFM.
g. Opacity (measured per USEPA reference Method 9).
h. Ammonia slip in ppmvd at 15% oxygen.

__**Verification:**__ The annual source test report shall be submitted to the District and CPM no later than six (6) weeks prior to the expiration date of the District permit.

AQ-15 The project owner shall, at least as often as once every five years (commencing with the initial compliance test), include the following supplemental source tests in the annual compliance testing:

a. Characterization of cold startup VOC emissions;
b. Characterization of warm startup VOC emissions;
c. Characterization of hot startup VOC emissions; and
d. Characterization of shutdown VOC emissions.

__**Verification:**__ Each annual source test report (**AQ-14**) shall either include the results of these tests for the current year or document the date and results of the last such tests.

AQ-16 Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B:

a. For NOx, Performance Specification 2.
b. For oxygen, Performance Specification 3.
c. For CO, Performance Specification 4.
d. For stack gas flow rate, Performance Specification 6 (if CERMS is installed).
e. For ammonia, a District approved procedure that is to be submitted by the project owner.
f. For stack gas flow rate (without CERMS), a District approved procedure that is to be submitted by the project owner.

__**Verification:**__ The project owner shall provide the CPM documentation of the District's approval of the continuous monitoring systems, within 15 days of its receipt. The project owner shall make the site available for inspection of the continuous monitoring systems by representatives of the District, CARB and the Commission.

AQ-17 The project owner shall submit to the APCO and USEPA Region IX the following information for the preceding calendar quarter by January 30, April 30, July 30 and October 30 of each year this permit is in effect. Each January 30 submittal shall include a summary of the reported information for the previous year. This information shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request:

a. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip.
b. Total plant operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, and hours in shutdown.
c. Date and time of the beginning and end of each startup and shutdown period.
d. Average plant operation schedule (hours per day, days per week, weeks per year).
e. All continuous emissions data reduced and reported in accordance with the District-approved CEMS protocol.
f. Maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NOx, CO, PM_{10}, VOC and SOx (including calculation protocol).
g. Fuel sulfur content (monthly laboratory analyses, monthly natural gas sulfur content reports from the natural gas supplier(s), or the results of a custom fuel monitoring schedule approved by USEPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG)
h. A log of all excess emissions, including the information regarding malfunctions/breakdowns required by Rule 430.
i. Any permanent changes made in the plant process or production which would affect air pollutant emissions, and indicate when changes were made.
j. Any maintenance to any air pollutant control system (recorded on an as-performed basis).

Verification: The project owner shall provide this information to the District and CPM in the Quarterly Operational Reports (**AQ-C7**).

AQ-18 The project owner must surrender to the District sufficient valid Emission Reduction Credits for this equipment before the start of construction of any part of the project for which this equipment is intended to be used. In accordance with Regulation XIII the operator shall obtain 202 tons of NOx, 49 tons of VOC, 47 tons of SOx, and 61 tons of PM_{10} offsets (Subject to U.S. EPA approval, NOx ERCs may be substituted for VOC ERCs at a rate of 1.0:1, and PM_{10} ERCs may be substituted for SOx ERCs at a rate of 1.0:1). The interpollutant offset ratios shall be approved by the U.S. EPA in conformance with District Rule 1305(B)(6)(a).

Verification: The project owner must submit all ERC documentation to the District and the CPM prior to the start of construction. If interpollutant offsets are used, the project owner shall provide evidence of U.S. EPA approval of such interpollutant offset ratios to the CPM prior to the start of construction.

AQ-19 During an initial commissioning period of no more than 180 days, commencing with the first firing of fuel in this equipment, NOx, CO, VOC and ammonia concentration limits shall not apply. The project owner shall minimize emission of NOx, CO, VOC and ammonia to the maximum extent possible during the initial commissioning period.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-20 The project owner shall tune each CTG and HRSG to minimize emissions of criteria pollutants at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-21 The project owner shall install, adjust and operate each SCR system to minimize emissions of NOx from the CTG and HRSG at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor. The NOx and ammonia concentration limits shall apply coincident with the steady state operation of the SCR systems.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-22 The project owner shall submit a commissioning plan to the District and the Energy Commission at least four weeks prior to the first firing of fuel in this equipment. The commissioning plan shall describe the procedures to be followed during the commissioning of the CTGs, HRSGs and steam turbine. The commissioning plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the timing of the dry low NOx combustors, the installation and testing of the CEMS, and any activities requiring the firing of the CTGs and HRSGs without abatement by an SCR system.

Verification: At least four (4) weeks prior to the first firing of natural gas in either turbine, the project owner shall submit a detailed Initial Commissioning Plan to the District and the CPM. This plan should provide detailed technical information regarding initial commissioning in a format that facilitates technical verification.

AQ-23 The total number of firing hours of each CTG and HRSG without abatement of NOx by the SCR shall not exceed 350 hours during the initial commissioning period. Such operation without NOx abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place and operating. Upon completion of these activities, the project owner shall provide written notice to the District and Energy Commission and the unused balance of the unabated firing hours shall expire.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report.

AQ-24 During a period that includes a portion of the initial commissioning period, emissions from this facility shall not exceed the following CO emission limits (verified by CEMS): 421 tons/year (rolling 12 month summary), 44,000 pounds/calendar day and 3700 pounds/hour.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report. In addition, after the end of the initial commissioning period the project owner shall continue to report the above data in the Quarterly Operational Report (**AQ-C7**) for as long as monitoring period includes a portion of the initial commissioning period.

AQ-25 During a period that includes a portion of the initial commissioning period, prior to the steady state operation of the SCR system, emissions from this facility shall not exceed the following NOx emission limits (verified by CEMS): 273 tons/year (rolling 12 month summary), 22,000 pounds/calendar day and 1000 pounds/hour.

Verification: During the initial commissioning period, the project owner shall submit a detailed record of all commissioning activities to the CPM in the Monthly Compliance Report. In addition, after the end of the initial commissioning period the project owner shall continue to report the above data in the Quarterly Operational Report (**AQ-C7**) for as long as monitoring period includes a portion of the initial commissioning period.

AQ-26 Within 60 days after achieving the maximum firing rate at which the facility will be operated, but not later than 180 days after initial startup, the operator shall perform an initial compliance test. This test shall demonstrate that this equipment is capable of operation at 100% load in compliance with the emission limits in Condition **AQ-4**.

Verification: Thirty (30) days prior to the initial compliance test, the project owner shall provide a written test plan for District review and approval. The project owner shall provide the CPM documentation of the District's approval of the test plan within 15 days of its receipt. Written notice of the initial compliance test shall be provided to the District and CPM ten (10) days prior to the tests so that an observer may be present. A written report with the results of such initial compliance tests shall be submitted to the District and CPM within forty-five (45) days after testing.

AQ-27 The initial compliance test shall include tests for the following. The results of the initial compliance test shall be used to prepare a supplemental health risk analysis:

a. Formaldehyde;
b. Certification of CEMS and CERMS (or stack gas flow calculation method) at 100% load, startup modes and shutdown mode;
c. Characterization of cold startup VOC emissions;
d. Characterization of warm startup VOC emissions;
e. Characterization of hot startup VOC emissions; and

f. Characterization of shutdown VOC emissions.

Verification: The results of the initial compliance test (see **AQ-26**) and a supplemental health risk analysis shall be submitted to the District and the CPM within forty-five (45) days after testing.

AQ-28 The project owner shall provide sufficient space and appurtenances within the Heat Recovery Steam Generator to allow the subsequent installation of a high temperature oxidation catalyst.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each HRSG, manufacturer and design data showing this feature. If any VOC or CO limit specified by the above conditions is violated, within six (6) weeks the project owner shall submit a plan to install an oxidation catalyst. The catalyst shall be installed and operational within six (6) months of the violation.

Duct Burner Conditions

[Two (2) individual 132 MMBtu/hr Natural Gas Duct Burners; MDAQMD Permit Numbers: B008879 and B008880]

AQ-29 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each duct burner system, manufacturer and design data. A summary of significant operation and maintenance events for each duct burner system shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-30 This equipment shall be exclusively fueled with natural gas and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, and Commission. A summary of significant operation and maintenance events for each duct burner system shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-31 The duct burner shall not be operated unless the combustion turbine generator with valid District permit # B08877 or B08878 and selective catalytic NOx reduction system with valid District permit # C008881 or C008882 are in operation.

Verification: A summary of fuel use and equipment operation for each duct burner shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-32 Fuel use by this equipment shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

Verification: The above information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District or Commission personnel upon request.

Selective Catalytic NOx Reduction System Conditions

[Two (2) individual SCR systems; MDAQMD Permit Numbers: C008881 and C008882]

AQ-33 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each selective catalytic reduction system, manufacturer and design data. A summary of significant operation and maintenance events for each selective catalytic reduction system shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-34 This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: A summary of significant operation and maintenance events for each selective catalytic reduction system shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-35 This equipment shall be operated concurrently with the combustion turbine generator with valid MDAQMD permit # B008877 or B008878.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and Commission upon request.

AQ-36 Ammonia shall be injected whenever the selective catalytic reduction system has reached or exceeded 550° Fahrenheit except for periods of equipment malfunction. Except during periods of startup and shutdown, ammonia slip shall not exceed 10 ppmvd (corrected to 15% oxygen), averaged over one hour.

Verification: The project owner shall maintain a log of the SCR temperatures and the commencement of ammonia injection times. This information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District and Commission personnel upon request.

AQ-37 Ammonia injection by this equipment in pounds per hour shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to MDAQMD personnel on request.

__**Verification:**__ The above information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District and Commission personnel upon request.

__Cooling Tower Conditions__

[One Cooling Tower; MDAQMD Permit Number: B008884]

AQ-38 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

__**Verification:**__ The project owner shall provide to the District and CPM, 30 days prior to installation of each cooling tower, manufacturer and design data. A summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-39 This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

__**Verification:**__ A summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-40 The drift rate shall not exceed 0.0006 percent with a maximum circulation rate of 146,000 gallons per minute (gpm), and the maximum Total Dissolved Solids shall not exceed 8190 ppm. The maximum hourly PM_{10} emission rate from this device and the evaporative condenser shall not exceed 2.00 pounds per hour, as calculated per the written District-approved protocol.

__**Verification:**__ Compliance documentation in accordance with the written District approved protocol shall be submitted to the District and the CPM.

AQ-41 The operator shall perform weekly tests of the blow-down water quality. The operator shall maintain a log that contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

__**Verification:**__ A summary of the results of the weekly blow-down water quality tests and the results of the mass emission rate calculations shall be submitted in the Quarterly Operational Reports (**AQ-C7**).

AQ-42 The operator shall conduct all required cooling tower water quality tests in accordance with a District-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District review and approval.

Verification: Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District and CPM review.

AQ-43 A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure is to be kept on-site and available to District personnel on request.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.

One Evaporative Condenser (Inlet Chiller

[MDAQMD Permit Number: B008883]

AQ-44 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of each cooling tower, manufacturer and design data. A summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-45 This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: A summary of significant operation and maintenance events for each cooling tower shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-46 The drift rate shall not exceed 0.0006 percent with a maximum circulation rate of 17,000 gallons per minute (gpm), and the maximum Total Dissolved Solids shall not exceed 8190 ppm. The maximum hourly PM_{10} emission rate from this device and the cooling tower shall not exceed 2.00 pounds per hour, as calculated per the written District-approved protocol.

Verification: Compliance documentation in accordance with the written District approved protocol shall be submitted to the District and the CPM.

AQ-47 The operator shall perform weekly tests of the blow-down water quality. The operator shall maintain a log that contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

Verification: A summary of the results of the weekly blow-down water quality tests and the results of the mass emission rate calculations shall be submitted in the Quarterly Operational Reports (**AQ-C7**).

AQ-48 The operator shall conduct all required cooling tower water quality tests in accordance with a District-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District review and approval.

Verification: Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District and CPM review.

AQ-49 A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure is to be kept on-site and available to District personnel on request.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.

Emergency Fire Pump Conditions

[One emergency IC engine driving a fire pump]

AQ-50 Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

Verification: The project owner shall provide to the District and CPM, 30 days prior to installation of the fire pump engine, manufacturer and design data. A summary of significant operation and maintenance events for the fire pump engine shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-51 This equipment shall be installed, operated and maintained in strict accord with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of contaminants.

Verification: A summary of significant operation and maintenance events for the fire pump engine shall be included in the Quarterly Operational Reports (**AQ-C7**).

AQ-52 This unit shall be limited to use for emergency fire fighting, and as part of a testing program that does not exceed 60 minutes of testing operation per week (up to two hours once per year for annual testing and up to four hours once every three years for triennial testing).

Verification: The project owner shall make the fire pump engine operating records available for inspection by representatives of the District, CARB and the Commission upon request. The information shall be maintained on-site for a minimum of five years and shall be provided to District and/or Commission personnel on request.

AQ-53 The project owner shall use only diesel fuel whose sulfur concentration is less than or equal to 0.05% on a weight per weight basis in this unit.

Verification: The project owner shall make fuel purchase, MSDS or other fuel supplier records containing diesel fuel sulfur content available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-54 The project owner shall maintain a log for this unit, which, at a minimum, contains the information specified below. This log shall be maintained current and on-site for a minimum of five (5) years and shall be provided to District personnel on request:

a. Date of each test;
b. Duration of each test in minutes;
c. Annual operation summary, in calendar year fuel consumption (gallons) or hours; and,
d. Fuel sulfur concentration (the project owner may use the supplier's certification of sulfur content if it is maintained as part of this log).

Verification: The project owner shall make the fire pump engine operating records available for inspection by representatives of the District, CARB and the Commission upon request.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

AIR QUALITY

APPLICABLE LAW	DESCRIPTION
FEDERAL	
Clean Air Act §111: 42 USC §7411; 40 CFR Part 60, subparts Db and GG	Establishes standards of performance to limit the emission of criteria pollutants for which the EPA has established national ambient air quality standards (NAAWS).
Clean Air Act §112 42 USC §7412; 40 CFR Part 63	Establishes national emission standards to limit hazardous air pollutant (HAP) emissions from existing major sources of HAP emissions in specific source categories.
Clean Air Act §160-169A 42 USC §7470-7491; 40 CFR Parts 51 & 53	Requires pre-construction review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. PSD applies only to pollutants for which ambient concentrations do not exceed the corresponding NAAQS (i.e., attainment pollutants).
Clean Air Act §171-193 42 USC 501 et seq.; 40 CFR Parts 51 & 52	Requires pre-construction review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment of ambient quality standards.
Clean Air Act §401 42 USC 654 et seq.; 40 CFR Part 72	Requires monitoring and reduction of emissions of acidic compounds and their precursors. The principal source of these compounds is the combustion of fossil fuels. Therefore, Title IV established national standards to limit SOx and NOx emissions from electrical power generating facilities.
Clean Air Act §501 (Title V) 42 USC §7661; 40 CFR Part 70	Requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, record-keeping and reporting requirements. Title V applies to major facilities, acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit.
Clean Air Act 501 (Title V) 42 USC §7414; 40 CFR Part 64	Requires facilities to monitor the operation and maintenance of emissions control systems and report any control system malfunctions to the appropriate regulatory agency.

Emergency Planning and Community Right-to-Know Act § 313 (EPCRA)	EPCRA requires certain facilities and establishments to report toxic releases to the environment if they: 1. Manufacture more than 25,000 lbs. of a listed chemical per year; 2. Process more than 25,000 lbs. of a listed chemical per year; or 3. Otherwise use more than 10,000 lbs. of a listed chemical per year.
STATE	
Health & Safety Code (H&SC) §39500 et seq.	Required by the Clean Air Act, the State Implementation Plan (SIP) must demonstrate the means by which all areas of the state will attain NAAQS within the federally mandated deadlines.
H&SC §40910-40930	The California Clean Air Act requires local Air Pollution Control District's (APCD) to attain and maintain both national and state AAQS at the earliest practicable date.

APPLICABLE LAW AIR QUALITY	DESCRIPTION
H&SC §39650-39675	The Toxic Air Contaminant Identification and Control Act created a two-step process to identify toxic air contaminants (TAC) and control their emissions. The ARB identifies and prioritizes the pollutants to be considered for identification as Tacos. The ARB then assesses the potential for human exposure to a substance while the Office of Environmental Health Hazard Assessment evaluates the corresponding health effects.
California Public Resources Code §25523(a); 20 CCR §§1752, 1752.5, 2300-2309, and Div. 2 Chap. 5, Art.1, Appendix B, Part(k)	Establishes requirements in the Sec's decision making process on an application for certification that assures protection of environmental quality.
LOCAL	
MDAQMD Regulation II, Rules 201 & 202	Requires an Authority to Construct (ATC and Permit to Operate (PTO) from the air district, as well as the requirement to obtain emission reduction credits.
MDAQMD Regulation IV.	Establishes prohibitions on facility operation, including nuisance, fugitive dust, PM_{10}, sulfur in fuels, etc.
MDAQMD Regulation XI, rule 1158	Establishes NOx emission standards for utility operations.
MDAQMD Regulation XIII Rules 1302, 1303, 1305 & 1306	Provides New Source Review procedures and requirements for emissions calculation including Best Available Control Technology (BACT) and for the qualification of offsets
MDAQMD Regulation XIV, Rules 1402 & 1404.	Establishes procedures for the registry and calculation of Emission Reduction Credits (ERCs).

BIOLOGY – Summary of Findings and Conditions

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Protected Species Impact	**None**	**None**	**YES**
	The power plant site is located on a highly disturbed, fenced parcel, adjacent to an operating power plant, intensive agriculture, a major interstate highway, and an airport. Although remnants of native plant and wildlife communities are in the region, the direct impacts from the project are not significant.		
Long-term Habitat Loss/ Degradation	**None**	**None**	**YES**
	The project would be located on the 66-acre site that has been previously graded and was fenced to exclude wildlife. Thus, the project is not expected to impact wildlife. The loss of the project site open space took place when the area was fenced for the adjacent power plant's excess fill disposal. The loss has already been compensated for under the BEP I expansion amendment. (FSA, p. 4.2-8)		

Short-term Construction Disturbance	MITIGATION	None	YES
	Construction would take place on a 66-acre section of the power plant site that has been previously fenced to exclude wildlife. However, the site will be managed to reduce potential harm to wildlife entering the area. The perimeter fence will be monitored to ensure its integrity during construction. Potential worker traffic-related desert tortoise fatalities can be reduced with a worker education program and appropriate speed limits. Burrowing owls were found during monitoring of the natural gas line installed for BEP I, but were not found on the BEP II project site in a 2004 survey. So long as natural vegetation is not restored prior to construction, burrowing owls and other sensitive species should not move onto the site. A pre-construction survey will determine the presence of burrowing owls, with avoidance measures taken, if necessary. Construction at night would require local area lighting and increase noise at a time that is typically dark and quiet, which could also increase risk to species that are nocturnal, such as kit foxes, when they enter the active construction zone. **MITIGATION:** ☑ The Project Owner will designate a biological resource specialist who will monitor ground disturbance, grading, construction and operation and has the authority to halt construction activities in an area of potential impact to sensitive biological resources. Conditions: **BIO-1** through **BIO-3**. ☑ The Project Owner shall implement a worker awareness program to inform employees about sensitive biological resources associated with the project. Condition: **BIO-4**. ☑ The Project Owner shall prepare a Biological Resources Mitigation Implementation and Monitoring Plan identifying measures to avoid impacts to sensitive biological resources. Condition: **BIO-5**. ☑ During construction, the Project Owner shall implement measures to avoid harm to biological resources, including a weed control program and fence monitoring. Conditions: **BIO-6** through **BIO-9**. ☑ Prior to construction, the Project Owner shall survey the project site for burrowing owls and will implement appropriate mitigation if burrowing owls are found. Condition: **BIO-10**. ☑ The Project Owner shall prohibit habitat disturbance in the fenced Cultural Resources Avoidance Area. Condition: **BIO-11**		

Operation Impact	MITIGATION	None	YES
	During operation, the cooling towers will emit mist and droplets of water into the atmosphere (known as cooling tower drift). Heavier droplets can fall onto soil and vegetation, and once evaporated, leave behind minerals and salts. The annual predicted deposition of cooling tower drift is less than one-third of the threshold to induce salt stress symptoms. The operation of the proposed facility would cause nitrogen oxide emissions from the combustion of natural gas. In addition to the nitrogen deposition from combustion, the proposed facility has nitrogen deposition from its air emission control technology in the form of ammonia. At this time, there are no sensitive communities or plants within the plume of the power plant. Joshua Tree National Park would not likely receive an increase in air pollutants because of its distance from the proposed BEP II project. The Applicant's proposal to reduce regional air quality impacts with the purchase of nitrogen-based emission reduction credits will likely improve air quality at the Park. As originally proposed, the BEP II project would have one evaporation pond, in much the same configuration as two existing ponds at BEP I. To avoid potential bird impacts from the evaporation ponds, the Applicant substituted a zero-liquid-discharge (ZLD) system utilizing brine crystallization technology. **MITIGATION:** ☑ The Project Owner shall discharge brine, distillate from the brine concentrator, and cooling tower blow down water to the evaporation ponds only in the cases of cooling system initial commissioning, maintenance, planned or forced outages or emergency. . Condition: **BIO-12**		

BIOLOGY - GENERAL

The proposed power plant is located in the Palo Verde Valley area of the Colorado Desert region, eastern Riverside County, just west of the Colorado River flood plain. The Palo Verde Valley was seasonally inundated by the Colorado River before several large dams were constructed upstream of Blythe. Since the installation of the dams and subsequent irrigation canals and drains, the Palo Verde Valley, and the surrounding terraces, have been transformed into a large agricultural area and service communities like Blythe have continued to grow. The remnant plant communities outside the agricultural and residential areas include: creosote bush scrub, disturbed desert areas with ruderal vegetation, and riparian plant communities along the Colorado River and various canals and drains.

A variety of sensitive species are found in the project region. Desert tortoises are found primarily on flats with scattered shrubs and abundant herbaceous plants, with soils ranging from sand to sandy-gravel. Mountain plover forage from September to March within agricultural fields which have been recently cleared or burned, but do not nest in California. The remainders of the species are concentrated along the banks of the Colorado River, which supports wetland and riparian communities.

East of the property are the Buck Boulevard Substation and BEP I, a 520-MW power plant, which became operational in December 2003. Beyond the 520-MW power plant facility is a large citrus grove, which has been recently abandoned and trees removed, and the Western Area Power Administration's Blythe Substation. To the west is a sewage treatment facility and beyond that is the Blythe Airport, which is a municipal facility, providing regional air services with a daily average of 67 takeoffs or landings. Hobsonway runs along the southern border of the project, and just south of that is Interstate 10. Hobsonway serves as an Interstate 10 frontage road and a city business loop. This section of Interstate 10 connects Los Angeles to Phoenix and Tucson, and is highly traveled. Properties to the north contain fallow agricultural lands and abandoned citrus groves that have revegetated with locally abundant native and ruderal species.

The southern half of the adjacent BEP I power plant facility contains two 8-acre evaporation ponds which receive wastewater brine from the power plant’s water treatment plant and cooling towers. The power plant has been discharging wastewater brine into the east evaporation pond since June 2003, but the west evaporation pond remains un-used. The west pond occasionally collects rainwater. The evaporation ponds have attracted flocks of wading birds, have been the site of several nests, and in general could be considered attractive to migratory and resident birds.

Power Plant Site

No sensitive species were identified on the site prior to the placement of fill. A permanent exclusionary fence surrounds the site. Although no sensitive species are expected within the fence line so long as it is maintained as compacted fill and gates are kept closed, an occasionally sensitive species may gain access to the site. For instance, a single kit fox was found trapped within the fence during a pre-construction survey on the site despite the fence being complete. Birds can also access the site, but they are not expected to nest due to the lack of vegetation.

Prior to the placement of fill on the site starting in May 2003, the vegetation community for the proposed power plant site and construction laydown area was Sonoran creosote scrub, dominated by creosote and white bursage on sandy and gravelly soils. The site had some off-road tracks on it, and some illegal dump sites were present. Sonoran creosote bush scrub is habitat for desert tortoise, a federal and state-listed species. Because the area had been categorized as potential desert tortoise and Harwood milk-vetch habitat, the permanent land disturbance was mitigated under the Blythe Amendment Biological Opinion and the Commission Order on the amendment (CEC 2002).

No vegetation remains on site, and the site is being maintained as compacted fill under an “Interim Weed and Erosion Control Program” (IWECP) which controls weeds with a polymer coating on the soil and occasional use of herbicides. The site will remain in this condition until August 2006, at which time the IWECP prescribes that natural vegetation be allowed to develop, so long as no industrial project is permitted on-site. This creates the possibility that the project may either be placed on either unvegetated compacted fill or on natural vegetation depending on the timing of the Commission Decision. Wildlife would be expected on site, if the site were returned to natural vegetation.

The Cultural Resource Avoidance Area on the northern end of the parcel has been fenced in a manner that will allow passage of desert tortoises, or other wildlife to use the area. Under the Blythe Amendment (CEC 2002), the habitat loss of this area was mitigated because the Applicant wanted to reserve the right to develop the area in the future without any additional permit review. The Cultural Resource Avoidance Area is covered with Sonoran creosote bush scrub. The Applicant has stated that no construction will take place on the 10-acre site during construction and operation of the proposed power plant.

Traffic to and from the site is mostly along Hobsonway and Interstate 10. These roads cross through urban development, agriculture, and some disturbed native scrub habitat. A power plant worker living in Blythe would cross several canals to reach work, including Goodman drain. To enter the site, workers would go north on Buck Boulevard between BEP I and the abandoned citrus grove, and then travel west on Riverside Avenue. The driveway from Riverside Avenue has desert tortoise-proof fencing on both the west and east side, and the gate has been built to be desert-tortoise proof. The area north of Riverside Avenue is undeveloped and is covered in Sonoran creosote bush scrub.

The City of Blythe upgraded Riverside Avenue to a 40-foot width within the 60-foot right-of-way. This work included drainage swales to divert the overland flows from the north to a drainage system at Buck Boulevard. The northwest corner of Riverside and Buck Avenues has some disturbance and soil compaction as it was used for waste storage during construction of the BEP I and the Buck Boulevard Substation. (FSA, pp. 4.2-6-7)

<u>Linear Facilities</u>

The natural gas pipeline that would service BEP II was built during the construction of the adjacent BEP I power plant. Electrical lines would need to be installed across the BEP I parcel to link the BEP II power plant to the Buck Boulevard Substation. The adjacent 76-acre parcel is industrial and no wildlife habitat remains with the exception of the bird use at the evaporation ponds. The Buck Boulevard switchyard, which was constructed on the BEP I parcel, is fully enclosed with a desert tortoise-proof fence and contains no wildlife habitat.

Protected Species Impact

The power plant site is located on a highly disturbed, fenced parcel, adjacent to an operating power plant, intensive agriculture, a major interstate highway, and an airport. Although remnants of native plant and wildlife communities are in the region, the direct impacts from the construction of the project are not significant. (FSA, p. 4.2-8)

Long-Term Habitat Loss/Degradation

The project would be located on the 66-acre site that has been previously graded and was fenced to exclude wildlife. Thus, the project is not expected to impact wildlife. The loss of the project site open space took place when the area was fenced for the adjacent power plant's excess fill disposal. The loss has already been compensated for under the BEP I expansion amendment. (FSA, p. 4.2-8)

Short-term Construction Disturbance

Since construction would take place on a 66-acre section of the power plant site that has been previously fenced to exclude wildlife, construction of the project is not expected to impact wildlife. However, the site will be managed to reduce potential harm to wildlife entering the area. The perimeter fence will be monitored to ensure its integrity during construction.

Workers and delivery vehicles would access the site from Riverside Avenue. While Buck Boulevard and Hobsonway have urban uses along their shoulders, Riverside Avenue is open to potential desert tortoise habitat to the north and has very little local traffic. A peak working day will generate 640 to 690 project-related trips on these roads, which could cause declines in desert tortoise sign out to 1.4 miles from the road. The high number of vehicles along Interstate 10 and Hobsonway has probably already depressed desert tortoise populations out to 2.6 miles, so project construction traffic would not add to this existing impact. However, potential traffic-related desert tortoise fatalities as vehicles exit the site and continue along Riverside Avenue can be reduced with a worker education program and appropriate speed limits.

Burrowing owls are in the area, and were found during monitoring of the natural gas line installed for BEP I, but were not found on the BEP II project site in a 2004 survey. This species would move onto the site only if natural vegetation is restored prior to project construction. Nesting activity will be assessed by pre-construction surveys within 30 days of project construction and if burrowing owls were found, then avoidance measures would be taken to reduce impacts to less than significant levels. The 10-acre Cultural Resource Avoidance Area on the north edge of the parcel is currently fenced, but does not limit access to burrowing owls or other wildlife. Since this area could become occupied with wildlife at any time, the project owner must survey for sensitive species prior to any disturbance of the area.

Construction at night would require local area lighting and increase noise at a time that is typically dark and quiet. It could also increase risk to species that are nocturnal, such as kit foxes, when they enter the active construction zone. Workers will be educated about the use of the site by wildlife in both daytime and nighttime, and lighting shall be shielded to reduce its impact off-site. (FSA, p. 4.2-8-9)

There are no impacts associated with the worker parking and staging area because it will be located on previously disturbed land that has been fenced to exclude desert tortoises.

MITIGATION:

- ☑ The Project Owner will designate a biological resource specialist who will monitor ground disturbance, grading, construction and operation and has the authority to halt construction activities in an area of potential impact to sensitive biological resources. Conditions: **BIO-1** through **BIO-3**.
- ☑ The Project Owner shall implement a worker awareness program to inform employees about sensitive biological resources associated with the project. Condition: **BIO-4**.
- ☑ The Project Owner shall prepare a Biological Resources Mitigation Implementation and Monitoring Plan identifying measures to avoid impacts to sensitive biological resources. Condition: **BIO-5**.
- ☑ During construction, the Project Owner shall implement measures to avoid harm to biological resources, including a weed control program and fence monitoring. Conditions: **BIO-6** through **BIO-9**.
- ☑ Prior to construction, the Project Owner shall survey the project site for burrowing owls and will implement appropriate mitigation if burrowing owls are found. Condition: **BIO-10**.
- ☑ The Project Owner shall prohibit habitat disturbance in the fenced Cultural Resources Avoidance Area. Condition: **BIO-11**

<u>Operation Impact</u>

During operation, the cooling towers will emit mist and droplets of water into the atmosphere (known as cooling tower drift). Heavier droplets can fall onto soil and vegetation, and once evaporated, leave behind minerals and salts. Cooling water is cycled several times, and chemicals are added to reduce scaling of pipes and other equipment, thus, any droplet is likely to have salt and chemical components. The Applicant estimates that the annual predicted deposition of cooling tower drift is less than one-third of the threshold to induce salt stress symptoms; thus, the operation of the proposed cooling towers is not expected to cause harm to surrounding vegetation. (FSA, p. 4.2-10)

The operation of the proposed facility would cause nitrogen oxide emissions from the combustion of natural gas. In addition to the nitrogen deposition from combustion, the proposed facility has nitrogen deposition from its air emission control technology in the form of ammonia. The nitrogen deposition rate considered sufficient to affect ecosystem structure and diversity is 3 to 10 kg/ha/yr depending on vegetation type. At this time, there are no sensitive communities or plants within the plume of the power plant, and thus the impact of ammonia deposition is adverse but not significant.

Joshua Tree National Park would not likely receive an increase in air pollutants because of its distance from the proposed BEP II project. Thus, the National Park Service does not believe that the proposed project will create an adverse impact on visibility or air quality related values at Joshua Tree National Park. The Applicant's proposal to reduce regional air quality impacts with the purchase of nitrogen-based emission reduction credits will likely improve air quality at the Park. (FSA, p. 4.2-19-20)

As originally proposed, the BEP II project would have one evaporation pond, in much the same configuration as two existing ponds at BEP I, which are on the parcel of land directly east of the proposed power plant site. In addition, the proposed power plant would use the same groundwater source as BEP I and would use the same technologies to concentrate the water before discharge to an evaporation pond. Project wastewater from the water treatment plant and the cooling towers would be allowed to evaporate unassisted. The wastewater from the brine concentrator would have a sodium concentration of over 58,000 milligrams per liter, which is nearly 1.5 times the salinity of ocean water. The wastewater would also have a high selenium concentration (1.8 mg/L).

The proposed evaporation pond would be likely to attract birds and other wildlife (e.g. insects, bats, etc.). Bird monitoring at BEP I's evaporation ponds documented use by several resident birds for their entire life cycle and by migratory birds on a seasonal basis. Another concern regarding the evaporation pond is the potentially undesirable result of attracting wildlife to the power plant site that is within 5,000 feet of the Blythe airport runway. The Federal Aviation Administration (FAA) recommends new water treatment ponds that are potentially attractive to wildlife be kept at least 5,000 feet distant from the runway for protection of approach and departure airspace. (FSA, pp. 4.2-10- 13).

To avoid potential biological impacts from the evaporation ponds, the project owner amended the project to substitute a zero-liquid-discharge (ZLD) system utilizing brine crystallization technology. Thus, the initially proposed evaporations ponds will not be used, except for shutdown or maintenance of the brine crystallizer. (Looper/Cameron/Gravahan, p. 6)

Agricultural Fallowing or Permanent Retirement

The Applicant intends to implement a Water Conservation Offset Program (WCOP) in in the amount of project water use. The Applicant proposes to retire irrigated lands permanently or fallow lands on a rotating basis to reduce demand for agricultural irrigation in the region. Fields in rotational fallowing would be left as stubble or as clodded earth for up to five years, and orchards may be removed. The use of agricultural land by sensitive wildlife, whether active or fallow, is limited due to the highly developed nature of the Mesa and Palo Verde Valley plateau and high human presence. No special status species are identified as residing on agricultural lands exclusively; however, wintering mountain plover are attracted to recently disturbed fields and sparse vegetation. Use of fallowed fields by the plover could increase with the lower level of human activity on the sites or decrease due to the loss of prey (grasshoppers). Overall, removing 786 acres of fields out of random and sporadic cycle of disturbance (from fire or tilling) would be small in comparison to the number of fields still in the vicinity (estimated at 104,000 irrigated acres). In addition, the sparse vegetation on the fallowed fields could be as attractive to the plover as a recently burned field, if prey items were available. No impacts to special status species are expected as a result of permanent retirement or fallowing of fields. (FSA, pp. 4.2-17 – 18)

Cumulative Impacts

Cumulative impacts are those that result from the incremental impacts of an action added to other past, present, and reasonably foreseeable future action, regardless of who is responsible for such actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.

Three major transmission projects within the area of the BEP II project are currently in permitting review.

The Imperial Irrigation District (IID) is overseeing the Desert Southwest Transmission Line Project (DSWTP), a proposed new 118-mile transmission line from Buck Boulevard Substation (on the BEP I site) to the Southern California Edison Company's Devers Substation, approximately 10 miles north of Palm Springs. BEP II proposes to connect with the DSWTP at the Buck Boulevard Substation. The DSWTP would be located entirely in a BLM-designated corridor. The project area is generally rural desert land with large amounts of undeveloped open space areas. The transmission line would cross desert tortoise habitat, with temporary and permanent impacts to desert tortoise lands. The project is under Section 7 consultation with the USFWS for impacts to desert tortoise and other federally listed species. (FSA, pp. 4.2-20-21) A joint Final Environmental Impact Report/Environmental Impact Statement (FEIR/EIS) identifies appropriate mitigation.

Additionally, the Energy Commission is currently reviewing the Blythe Energy Project Transmission Line (BEPTL) Petition for Post-Certification Amendment (99 AFC-8C). As of the preparation of this document, BEP I has amended its application to expand its connection at Buck Boulevard Substation and proposes two transmission line connections. One connection is 7 miles, and a second is 67 miles in length. In addition, there is a proposal for a new substation called MidPoint, which would impact 40 acres of desert tortoise habitat. Energy Commission staff has identified potential impacts from the transmission lines and substation upon desert tortoise, burrowing owl, Harwood's milk-vetch, Cove's cassia, crucifixion thorn, mesquite nest-straw, Orocopia sage, and Mojave fringe-toed lizard. Staff has proposed Conditions of Certification that would mitigate these potential impacts to a level of insignificance. (FSA, p. 4.2-22)

Lastly, Southern California Edison's (SCE) Palo-Verde to Devers II Project has been in planning for over 20 years. SCE has applied for a permit from the California Public Utilities Commission, which must determine that the project has a legitimate public need and would result in public good.

The proliferation of approved utility corridors, along with the attraction of transmission line roads for off-road enthusiasts, has resulted in negative impacts to desert tortoise communities. These negative impacts are significant for their individual impact as well as collectively because fewer undisturbed desert locations remain as a result of a series of decisions to allow more utility corridors. (FSA, p. 4.2-22) Appropriate mitigation in each permitting proceeding is capable of reducing its respective project's potential impacts to less than significance, thus rendering the potential cumulative impact less than significant.

Finding

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to biological resources and all potential biological resource impacts will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

DESIGNATED BIOLOGIST SELECTION

BIO-1 The project owner shall submit the resume(s), including contact information, of the proposed Designated Biologist and any Biological Monitor(s) to the Compliance Project Manager (CPM) for approval.

Verification: The project owner shall submit the resume and contact information for the Designated Biologist and Biological Monitor(s) to the CPM at least 60 days prior to the start of any site (or related facilities) mobilization. The Designated Biologist must have a thorough understanding of the Conditions of Certification, the federal and state permits, and the monitoring procedures established in the BRMIMP. Site and related facility activities shall not commence until an approved Designated Biologist is available to be on site and to train all Biological Monitors. Biological Monitor(s) training shall include familiarity with the Conditions of Certification, the federal and state permits, and the monitoring procedures established in the BRMIMP.

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

The Biological Monitor(s) shall have a background in biology or environmental science and be approved by the CPM. If a Designated Biologist needs to be replaced, the specified information of the proposed replacement must be submitted to the CPM at least ten working days prior to the termination or release of the preceding Designated Biologist. In an emergency, the project owner shall immediately notify the CPM and submit the qualifications of a short-term replacement. The CPM shall approve the short-term replacement within one business day. The short-term replacement shall have all the duties and rights of a Designated Biologist while a permanent Designated Biologist is proposed to the CPM for consideration.

DESIGNATED BIOLOGIST AND BIOLOGICAL MONITOR DUTIES

BIO-2 The project owner shall ensure that the Designated Biologist and Biological Monitor(s) shall perform the following:

1. Advise the project owner's Construction and Operation Managers on the implementation of the biological resources Conditions of Certification;
2. Be available to supervise or conduct mitigation, monitoring, and other biological resources compliance efforts, particularly in areas requiring avoidance or containing sensitive biological resources, such as wetlands and special status species or their habitat;
3. Clearly mark sensitive biological resource areas and inspect these areas at appropriate intervals for compliance with regulatory terms and conditions;
4. Notify the project owner and the CPM of any non-compliance with any biological resources Condition of Certification; and
5. Respond directly to inquiries of the CPM regarding biological resource issues.

Verification: The project owner shall ensure that the Designated Biologist and Biological Monitor(s) maintain written records of the tasks described above, and summaries of these records shall be submitted in the Monthly Compliance Reports (MCR). During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report.

DESIGNATED BIOLOGIST AND BIOLOGICAL MONITOR AUTHORITY

BIO-3 The project owner's Construction/Operation Manager shall act on the advice of the Designated Biologist or Biological Monitor(s) to ensure conformance with the biological resources Conditions of Certification.

If required by the Designated Biologist or 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 as sensitive or which may affect a sensitive area or species.

The Designated Biologist and Biological Monitor(s) shall:

1. Require a halt to all activities in any area when it is determined that there would be an adverse impact to sensitive species 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 halt.

<u>Verification:</u> The Designated Biologist shall notify the CPM and project owner immediately (no later than the following morning of 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

BIO-4 The project owner shall develop and implement a CPM approved Worker Environmental Awareness Program (WEAP) in which each of its employees, as well as employees of contractors and subcontractors who work on the project site or any related facilities during site mobilization, ground disturbance, grading, construction, and operation are informed about sensitive biological resources associated with the project.

The WEAP must:

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 is made available to all participants;
2. Discuss the locations and types of sensitive biological resources on the project site and adjacent areas;
3. Present the reasons for protecting these resources;
4. Present the meaning of various temporary and permanent habitat protection measures;
5. Identify whom to contact if there are further comments and questions about the material discussed in the program; and
6. Include a training acknowledgment form to be signed by each worker indicating that they received training and shall abide by the guidelines.

A competent individual(s) acceptable to the Designated Biologist can administer the specific program.

<u>Verification:</u> At least 60 days prior to the start of any site (or related facilities) mobilization, the project owner shall provide to the CPM two (2) copies of the WEAP and all supporting written materials 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.

The project owner shall keep the signed training acknowledgement forms on file for a period of at least six months after the start of commercial operation. During project operation, signed statements for active project 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 (BRMIMP)

BIO-5 The project owner shall submit two copies of the proposed BRMIMP to the CPM (for review and approval) and to CDFG and USFWS (for review and comment) and shall implement the measures identified in the approved BRMIMP.

The final BRMIMP shall identify:

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 in the Commission’s Final Decision;
3. All biological resource mitigation, monitoring and compliance measures required in federal agency terms and conditions, such as those provided in the USFWS Biological Opinion;
4. All biological resources mitigation, monitoring and compliance measures required in other state agency terms and conditions, such as those provided in the CDFG Incidental Take Permit and Streambed Alteration Agreement and Regional Water Quality Control Board permits;
5. All biological resources mitigation, monitoring and compliance measures required in local agency permits, such as site grading and landscaping requirements;
6. All sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation and closure;
7. All required mitigation measures for each sensitive biological resource;
8. Required habitat compensation strategy, including provisions for acquisition, enhancement, and management for any temporary and permanent loss of sensitive biological resources;
9. A detailed description of measures that shall be taken to avoid or mitigate temporary disturbances from construction activities;
10. 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 if construction will disturb lands outside of the existing permanent fence;
11. If construction will disturb lands outside of the existing permanent fence, then supply aerial photographs, at an approved scale, of all areas to be disturbed during project construction activities - one set prior to any site or related facilities mobilization disturbance and one set subsequent to completion of project construction. Include planned timing of aerial photography and a description of why times were chosen;

12. Duration for each type of monitoring and a description of monitoring methodologies and frequency;
13. Performance standards to be used to help decide if/when proposed mitigation is or is not successful;
14. All performance standards and remedial measures to be implemented if performance standards are not met;
15. A process for proposing plan modifications to the CPM and appropriate agencies for review and approval; and
16. A copy of all biological resources permits obtained.

Verification: The project owner shall provide the specified document at least 30 days prior to start of any site (or related facilities) mobilization. The CPM, in consultation with the CDFG, Western Area Power Administration, the USFWS and any other appropriate agencies, will determine the BRMIMP's acceptability within 45 days of receipt.

The project owner shall notify the CPM no less than five (5) 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 CDFG, Western Area Power Administration, the USFWS and appropriate agencies to ensure no conflicts exist.

Within thirty (30) days after completion of project construction, the project owner shall provide to the CPM, for review and approval, a written 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.

CONSTRUCTION MITIGATION MANAGEMENT TO AVOID HARASSMENT OR HARM

BIO-6 The project owner shall manage their construction site, and related facilities, in a manner to avoid or minimize impacts to the local biological resources.

Measures to be implemented are:

1. Install a temporarily fence and provide wildlife escape ramps for construction areas that contain steep walled holes or trenches if located outside of an approved, permanent exclusionary fence. The fence around the 66-acre site is an approved, permanent exclusionary fence. The temporary fence shall be hardware cloth or similar materials that are approved by USFWS and CDFG;
2. Ensure all food-related trash is disposed of in closed containers and removed at least once a week.
3. Prohibit feeding of wildlife by staff or contractors;
4. Prohibit non-security related firearms or weapons from being brought to the site;
5. Prohibit pets from being brought to the site;
6. Report all inadvertent deaths of sensitive species to the appropriate project representative. Injured animals shall be reported to CDFG and the project

owner shall follow instructions that are provided by CDFG. . All incidences of wildlife injury or mortality resulting from project-related vehicle traffic on roads used to access the project shall be reported in the MCR;

7. Minimize use of rodenticides and herbicides in the project area;
8. Cover selected electrical equipment with the potential to electrocute wildlife within the substation with appropriate UV resistant material;
9. Shield lighting to prevent off-site impacts and when night-time construction is approved by the CPM, and then limit its use during night-time construction to only what is necessary to complete the approved work or when worker safety is an issue of concern;
10. Design and install power lines following Avian Power Line Interaction Committee's guidelines;
11. Follow the July 1999 (or most current) desert tortoise handling procedures whenever a desert tortoise is encountered; and
12. Post speed limits for construction-related traffic on Riverside Avenue and take actions against repeat offenders.

Verification: All mitigation measures and their implementation methods shall be included in the BRMIMP.

EXOTIC WEED CONTROL PROGRAM

BIO-7 During construction and operations, a comprehensive exotic weed control program for California Department of Agriculture List A, List B, and Red Alert weeds, shall be implemented at the 66-acre power plant site. This program shall be implemented until such time that the adjacent land use on the north and west sides in no longer a natural community or agriculture, or until the plant is permanently closed. The natural vegetation adjacent to the BEP II site shall be monitored to determine if it has been modified or degraded. Any seed mixture applied following ground disturbance shall be certified as weed-free.

Verification: Thirty days prior to mobilization, the project owner shall submit a weed control report to the CPM for approval and to Western Area Power Administration for comment. The report shall include photos of the adjacent land or otherwise document any changes in an annual report until such time as the CPM approves cessation. The project owner shall submit the seed mixture to be used following ground disturbance.

FENCE MONITORING

BIO-8 The project owner shall conduct monthly maintenance monitoring of the wildlife exclusion fencing and complete repairs within one week of a problem being identified. Temporary fencing must be installed at any gaps if it shall remain open overnight.

Verification: The project owner shall submit records of all monitoring dates, identify the locations that required repair, and any corrective actions taken in the MCR and Annual Compliance Report.

CONFINED WILDLIFE

BIO-9 The Designated Biologist or Biological Monitor shall be contacted if wildlife is found within the fenceline during construction and if it does not leave voluntarily without physical contact or harassment within 24 hours of being found. Actions to prevent physical harm to any wildlife from construction equipment shall immediately be taken by on-site staff. The local office of the California Department of Fish and Game shall be contacted if sensitive wildlife is found within the fenceline during operations.

Verification: For any wildlife found within the fenceline during construction a report shall be completed by the Designated Biologist and submitted with the MCR. For any wildlife found within the fenceline during operations, a report shall be completed by the plant manager and submitted with the Annual Compliance Report.

BURROWING OWL SURVEYS AND COMPENSATION FOR IMPACTS

BIO-10 The project owner shall conduct a pre-construction survey(ies) for burrowing owl activities to assess owl presence and need for further mitigation. The Designated Biologist or Biological Monitor(s) shall monitor active burrows throughout construction to identify additional losses from nest abandonment. The project owner shall protect lands and enhance or install burrows to compensate for impacts to active burrows at the site, along related facilities, or within 150 feet of these features. The project owner shall protect lands to compensate for permanent losses of potential upland foraging habitat.

Based on the burrowing owl survey results, the following three actions shall be taken by the project owner to offset impacts during construction:

1. Where a burrowing owl is sighted:

    a. If paired owls are present in areas scheduled for disturbance or degradation (e.g., grading) or within 150 feet of a permanent project feature, and nesting is not occurring, owls are to be removed per CDFG-approved passive relocation. Passive relocation is only acceptable typically from September 1 to January 31, to avoid disruption of breeding activities. The specific dates for acceptable passive relocation are dependent on the end of burrowing owl nesting season during that calendar year.
    b. If paired owls are present within 150 feet of a temporary project disturbance (e.g., transmission line stringing), active burrows shall be monitored by the Designated Biologist or Biological Monitor(s) throughout construction to identify additional losses from nest abandonment and/or loss of reproductive effort (e.g., killing of young).
    c. If paired owls are nesting in areas scheduled for disturbance or degradation, nest(s) shall be avoided from February 1 through August 31 by a minimum of a 250-foot buffer or until fledging has occurred. The specific dates for acceptable passive relocation are dependent on the end of burrowing owl nesting season during that calendar year. Following fledging, owls may be passively relocated.

2. Based on the actions taken during construction, the project owner shall provide a land protection and monitoring proposal for CPM approval, and to the CDFG for review 60 days prior to commercial operation. The land protection shall be based on the following premises:
   a. To offset the loss of active foraging and burrow habitat, the project owner shall provide 6.5 acres of protected lands within the Palo Verde Valley for each pair of owls or unpaired resident bird that was passively relocated or for which project-related disturbance caused nest abandonment and/or loss of reproductive effort (e.g., killing of young). Protection of additional habitat acreage per pair or unpaired resident bird may be applicable in some instances (such as for gross negligence on the part of the project owner or a contractor).
   b. To offset the permanent loss of potential foraging and burrow habitat, the project owner must provide 0.5 acre of land within the Palo Verde Valley for every acre of suitable habitat they permanently converted to an unsuitable use (e.g., ponds or buildings) that was within 300 feet of a burrowing owl pair or unpaired resident.
   c. The project owner's protected lands shall be within 1,800 feet of occupied burrowing owl habitat.
   d. For each occupied burrow destroyed during construction, existing unsuitable burrows on the protected lands shall be enhanced (e.g., cleared of debris or enlarged) or new burrows installed at a ratio of 2:1.
   e. The project owner must provide funding for long-term management and monitoring of protected lands based on the Center for Natural Lands Management Property Analysis Record, or similar cost analysis program.

<u>Verification:</u> The project owner shall survey for burrowing owl activities to assess owl presence and need for further mitigation 30 days prior to site mobilization. If construction is delayed or suspended for more than 30 days after the survey, the area shall be resurveyed. Surveys shall be completed for occupied burrows at the fenced parcel and for a 500-foot buffer around these features (where possible and appropriate based on habitat). All occupied burrows shall be mapped on an aerial photo. At least 15 days prior to the expected start of any project-related ground disturbance activities, or restart of activities, the project owner shall provide the burrowing owl survey results and mapping to the CPM, Western Area Power Administration, and CDFG.

Within 30 days prior to the start of commercial operation, the project owner shall submit to the CPM two copies of the relevant legal paperwork that protects lands in perpetuity (e.g., a conservation easement as filed with the Riverside County Assessor), and any related documents that discuss the types of habitat protected on the parcel. If a private mitigation bank is used, the project owner shall provide a letter from the approved land management organization stating the amount of funds received, the amount of acres purchased in long-term management, and their location.

FUTURE WORK ON CULTURAL RESOURCES AVOIDANCE AREA

BIO-11 The project owner shall prohibit habitat disturbance in the Cultural Resources Avoidance Area unless the Western Area Power Administration, U.S. Fish and Wildlife

Service, California Department of Fish and Game, and the CPM have been adequately notified in writing and have given approval. The use of light-duty vehicles shall be limited and shall only be operated during the daylight hours. All persons entering the Cultural Resources Avoidance Area must have completed the Worker Environmental Awareness Program. Thirty (30) days prior to activity within the Cultural Resource Avoidance Area, it shall be fenced in a manner that excludes desert tortoise with a biological monitor present. A clearance survey for desert tortoises within the fenceline must be completed prior to commencing work within the fenceline.

Verification: A summary of any activities in the Cultural Resource Avoidance Area shall be made part of the annual reporting to the CPM. All dates of entry and purpose, a copy of signed training acknowledgement forms, and a report on any wildlife sightings shall be part of the annual report. The project owner shall notify the CPM, Western Area Power Administration, U.S. Fish and Wildlife Service, and California Department of Fish and Game 60 days prior to any proposed construction in the Cultural Resource Avoidance Area. The results of the desert tortoise clearance survey shall be sent to the same parties listed above for review and comment prior to initiating construction within the fenceline.

EVAPORATION POND USE

BIO-12 The project owner shall discharge brine, distillate from the brine concentrator, and cooling tower blow down water to the evaporation ponds only in the cases of cooling system initial commissioning, maintenance, planned or forced outages or emergency. The project owner shall notify the CPM in case of any discharge. At the earliest opportunity, when supported by plant operations, the water shall be pumped from the evaporation ponds to the cooling tower basin, brine concentrator or brine crystallizer (as appropriate) for processing until the evaporation ponds have been emptied.

The project owner shall prepare an Evaporation Pond Mitigation and Monitoring Plan to ensure that any impacts from the discharge are mitigated. If a substantial number of bird, wildlife, or protected species are found using the ponds, then remedial actions to reduce wildlife use to a less than significant level and to prevent nesting must be implemented. When such a discharge occurs to the evaporation pond, remedial measures shall be performed to discourage nesting and reduce bird and wildlife exposure to the ponds. The project owner shall provide notice to the CPM and submit records of all monitoring dates, data collected, and any corrective actions taken in the Evaporation Pond Monitoring Report. After any facility closure of more than four (4) months, and at a time when the ponds do not have water in them, the ponds shall be cleaned if it is determined by the CPM the sediment presents a risk of contamination to wildlife. No clean-up of clean, untainted sediment that is windblown into the ponds is required.

The Evaporation Pond Mitigation and Monitoring Plan shall identify:

1. All biological resources to be impacted, avoided, or mitigated by evaporation pond use or closure.
2. A detailed description of all biological resources mitigation, monitoring, and compliance measures included in the Commission's Final Decision, the Federal

and State Endangered Species Act, the California Environmental Quality Act, and the Migratory Bird Treaty Act;

3. A detailed description of methods to be used to avoid or discourage bird and wildlife use and to prevent nesting following any period of discharge;
4. Detailed description of remedial measures to be performed if initial methods do not meet specified condition;
5. The individual(s) who are responsible for monitoring and reporting;
6. The estimated dates of planned outages, duration, number of times per year, and volume for discharges to the evaporation ponds;
7. Monitoring frequency and dates, conditions, data collected, , reporting periods, and actions to be implemented following a discharge;
8. The cleaning schedule after any discharge to the ponds;
9. Reporting procedures to be followed in the case of any unplanned or emergency discharge;
10. Methods to remove chemical residue in the ponds should a facility closure occur for more than four months; and
11. Reporting procedures following a facility closure for more than four months.

Verification: At least ninety (90) days prior to commencing construction of the evaporation ponds, the project owner shall provide two copies of the Evaporation Pond Mitigation and Monitoring Plan and all supporting materials to the CPM for review and approval.

The CPM, in consultation with the CDFG, USFWS, and any other appropriate agencies, will determine the plan's acceptability within forty-five (45) days of receipt, if possible. Any modifications to the plan will follow the same approval and time periods as those for the BRMIMP (**BIO-5**).

The project owner shall submit an Evaporation Pond Monitoring Report to the CPM on a quarterly basis. The Evaporation Pond Monitoring Report shall include event specific details as requested in #7 – 10 above. The monitoring shall continue for at least the first three years of power plant operation, and depending on the results, could be discontinued after written notice from the CPM, and consultation with CDFG and USFWS, if there is no evidence of significant wildlife exposure to the evaporation ponds.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

BIOLOGY

APPLICABLE LAW	DESCRIPTION
FEDERAL	
Endangered Species Act of 1973 (16 USC, Section 1531 et seq.) and implementing regulations, (CFR, Section 17.1 et seq.)	Designates and provides for protection of threatened and endangered plants and animals and their critical habitat.
Migratory Bird Treaty Act (16 USC, Sections 703-712)	Prohibits “take” (i.e., harass, hunt, or kill) or any attempts to take migratory birds.
Executive Order 13186 and Director’s Order No. 172	Orders federal agencies to promote the conservation of migratory birds in all their actions through a Memorandum of Agreement and creation of a new Council for the Conservation of Migratory Birds. USFWS is responsible for the prevention or abatement of the pollution or detrimental alteration of the environment for the benefit of migratory birds within the scope of its statutory authorities.
STATE	
California Endangered Species Act of 1984, (Fish and Game Code, Section 2050 et seq.)	Protect California’s endangered and threatened species.
LOCAL	
Riverside County, California General Plan; Environmental Hazards and Resources	Goal 6 is to recognize and protect rare, threatened and endangered species of wildlife and vegetation as important County resources and a source of natural diversity. Goal 8 is to recognize and promote the conservation of unique species of wildlife and vegetation found within a locale as an important County resource.
City of Blythe, General Plan, Biological Resources Goal 1 & Policy 1, 2, 4 & 8	Preserve and protect City and regional biological resources, especially those of sensitive, rare, threatened, or endangered species of wildlife and their habitat and to encourage a balance between nature and human development.

CULTURAL RESOURCES – Summary of Findings and Conditions

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Cultural Resources ▪ **Prehistoric** ▪ **Historic** ▪ **Ethnic Heritage**	**MITIGATION**	**None**	**YES**
	Construction: As part of the BEP I project and its subsequent Amendments, an intensive walking survey of the BEP I site revealed four historic sites and two isolated prehistoric artifacts. The two isolated prehistoric artifacts consisted of a single flake and core of chert. Four archeological deposits were determined to be ineligible for the California Register of Historical Resources and were destroyed as part of the BEP I development. Two archeological deposits, within the proposed BEP II plant site, were explored and recovered during the BEP I development. The project area contains Native American sites for trails, habitation, cremation, and burial. **MITIGATION:** ☑ The Project Owner will designate a cultural resource specialist who will monitor excavation and, in the event of an unanticipated discovery, provide for the handling and curation of any recovered cultural resources. Conditions: **CUL-1** through **CUL-7**. ☑ Given the proximity of the project to sacred Native American sites, the Project Owner shall invite tribal leaders to bless the project area and conduct other appropriate ceremonies. Condition: **CUL-9**		

CULTURAL RESOURCES- GENERAL

This analysis discusses cultural resources, which are defined as the structural and cultural evidence of the history of human development and life on earth. Cultural resources may be found on the ground surface or buried beneath the surface. Evidence of California's early occupation is becoming increasingly vulnerable due to the ongoing development and urbanization of the state. Potential cultural resources are identified through records searches and field surveys.

Since project development and construction usually entail surface and sub-surface disturbance of the ground, the proposed project has the potential to adversely affect both known and unknown cultural resources. Direct impacts are those that may result from the immediate disturbance of resources, whether from vegetation removal, vehicle travel over the surface, earth-moving activities, or excavation. Indirect impacts are those that may result from increased erosion due to site clearance and preparation, or from inadvertent damage or outright vandalism to exposed resource materials due to improved accessibility. Cumulative impacts to cultural resources may occur if increasing amounts of land are cleared and disturbed for the development of multiple projects in the same vicinity as the proposed project.

Prehistoric

Prehistoric archaeological resources are those resources relating to prehistoric human occupation and use of an area; these resources may include sites and deposits, structures, artifacts, rock art, trails, and/or any other traces of Native American human behavior. In California, the prehistoric period has been determined to pre-date 10,000 years before present (B.P.) and which extended well into the 18th century with the initiation of the Mission Period (ca. 1769) and the first Euro-American (Spanish) settlement of California.

The first well-dated Native American occupation of the Colorado River Valley is the San Dieguito complex, dating between 7,000 and 12,000 years before present (BP). It is assumed from the material culture remains that these people employed a hunter-gatherer adaptation based on small mobile bands exploiting game and collecting seasonally available wild plants. Settlement patterns indicate sites typically located on mesas and terraces overlooking larger washes and around the edges of lakes. Early San Dieguito tools include bifacial and unifacially reduced choppers and chopping tools, concave-edged scrapers, bilateral-notched pebbles, and scraper planes. Later, finely made blades, smaller bifacial points, and a variety of scraper and chopper types were introduced. Finally, fine pressure flaking techniques, including pressure-flaked blades, leaf-shaped projectile points, scraper planes, plano-convex scrapers, crescents (amulets), and elongated bifacial knives become part of the inventory.

Few Archaic period (7,000 and 1,000 years BP) sites have been dated in the desert on either side of the Colorado River. The economy can be seen as exploitation of a variety of food resources, including large and small animals. Generally, the Archaic period in the Western United States saw a diversification of artifact assemblages, including the introduction of the use of ground stone technology to exploit seasonally available seeds and nuts. However, such evidence is lacking in the Lower Colorado River area.

The Late Prehistoric period in the lower Colorado River Region has been referred to as "Patayan" first recognized with the introduction of pottery approximately 1,200 years ago. The presence of Desert Side-notched and Cottonwood type projectile points at about 1,500 years BP may indicate an early pre-ceramic phase. The introduction of floodplain agriculture, the bow and arrow, and a change in burial practices characterizes this period. Population growth, along with more sedentary villages, resulted from a heavy reliance on grown foods rather than wild foods. An extensive trail system across the desert was established that linked the Lower Colorado River peoples with related groups in the greater Southwest, the Gulf of California and the Pacific Ocean. Trails are often associated with ceramic "pot-drops," shrines, and other evidence. Many of the Colorado Desert pictographs, petroglyphs, and bedrock grinding surfaces are also associated with the Patayan pattern. Away from the Colorado River, higher elevations were used for desert resource collection, particularly during periods of flooding. Wild foods are estimated to have accounted for 40 to 70 percent of the diet. (FSA, p. 4.3-4-5)

Historic

Historic archaeological resources are those materials usually associated with Euro-American exploration and settlement and the beginning of written historical records. Historic resources may also include archaeological deposits, sites, structures, traveled ways, artifacts, documents, and/or any other evidence of human activity. Prior to 1998, federal and state requirements identified historic resources as being greater than fifty years of age. Amendments to CEQA have removed the references to the fifty-year designation, while the federal regulations maintain the requirement.

Europeans first entered what is now southeastern California in 1540 when Hernando de Alarcon sailed up the Colorado River from the Gulf of California to the vicinity of present day Yuma, Arizona. This expedition interacted with the Yuman speaking Native Americans who had occupied the area for some time. Contact between these groups continued over the next two centuries, but the Spanish largely focused their colonizing efforts on areas to the south and east. It was not until missions were established in the region in the late eighteenth century that Yuman cultures were directly affected by Spanish incursion. Conflicts increased in scale and frequency, but the Yumans resisted Spanish domination.

Anglo-American settlers entered the region following the Mexican War and the Gold Rush in the late 1840's. Fort Yuma was established in 1852 and six years later, the U.S. Army defeated the combined forces of the Mojave and Quechan. Following the pacification of the region, miners, farmers, and cattle ranchers arrived in increasing numbers.

In 1874, San Francisco millionaire Thomas H. Blythe applied for land rights in the Palo Verde Valley region of the Colorado River Valley under California's Swamp and Overflow Act of 1868, which gave land that was perennially swamp or subject to flooding to anyone who would fill, drain, or put the land to good use. Blythe later obtained 35,971 additional acres under the Federal Desert Land Act in 1877, becoming the dominant private landowner in the valley. Blythe applied for 190,000 miner's inches of Colorado River Water on July 17, 1877, increasing the amount to 385,000 miner's inches by February 15, 1883. In 1879, civil engineer Oliver P. Callaway, partner of Blythe, began digging canals and set up an experimental farm, known as the Colorado Colony. This marked the beginnings of irrigated agriculture in the Palo Verde Valley. By 1904, the town of Palo Verde was a small hamlet, and a store and post office were established. Steamboats along the Colorado River were the primary means of transportation to and from Blythe until 1908, when the Laguna Dam was built above Yuma. Stages handled the need to move people and goods thereafter. However, despite growth, flooding of the Colorado River continued to impede agricultural efforts. It was not until the mid-1930s and the construction of Hoover Dam that flooding was finally controlled.

Transportation routes were continually improved. The railroad had never entered the valley so overland roads and trails dominated transportation. Finally, a railroad spur was built to Blythe Junction, and it was extended to Blythe itself in 1915. Most early roads followed the railroad tracks or old wagon roads. The federal highway, now Interstate 10, was paved from Indio to Blythe in 1936.

During the Depression of the 1930's, many farmers and farm laborers from the dust bowl came to California, including the Palo Verde Valley, looking for work in agriculture, mining or other laboring professions. Several large water projects, such as the All-American Canal, were undertaken with the help of the large pool of inexpensive labor. At the start of World War II, the Blythe Municipal Airport was taken over by the U.S. Army and designated Morton Air Academy; 650 buildings and 8,000-foot runways were constructed. The airport became the home to the 390th Bomb Group, consisting of four squadrons of B-17 Flying Fortresses. The Air Academy served about 8,000 men and several hundred WACs. Wives and families of servicemen swelled the population of Blythe to over 4,000, many living in box cars, sheds, spare rooms, and empty buildings.

During the same period, the U.S. Army Ground Forces established the Desert Training Center (DTC) that was renamed the California-Arizona Maneuver Area (C-AMA) in 1943. The DTC/C-AMA was an armored training facility for the preparation of troops for the invasion of North Africa. The facility covered over 18,000 square miles and served in excess of one million troops. The Blythe Army Air Base, in the middle of DTC/C-AMA, was likely used for transportation and supply purposes. Training at the DTC/C-AMA continued until 1944, and the Morton Air Academy ceased military training operations in the same year. The airfield returned to its former role as a municipal airport, with much-improved runway and support buildings. Portions of the facility have been used by Palo Verde Valley High School, and later Palo Verde College. The male college students used the barracks as dormitories until the college found new facilities. Few of the structures of the Morton Air Academy still exist. The most prominent building in the area of the airfield is a hanger.

As part of the BEP I project and its subsequent Amendments, an intensive pedestrian survey of the property was completed. The survey of the 76-acre BEP I site revealed four historic sites and two isolated prehistoric artifacts. The two isolated prehistoric artifacts found on the plant site consist of a single flake and core of chert. Four archeological deposits recorded in the BEP I site area were determined to not meet the criteria for eligibility for the CRHR. These four deposits were destroyed as part of the BEP I development and will not be discussed further in this analysis.

Two archeological deposits were recorded within the BEP I expansion areas (10 Acre and Earth Fill Amendments) and are within the proposed BEP II plant site. The recording and subsurface testing of CA-Riv-6725H recovered the information values that the deposit contained. Consequently, the deposit no longer meets the criteria for eligibility for the CRHR.

The historic military use of the Blythe Army Air Base and/or the Desert Training Area has left refuse scatter, CA-Riv-6370H, consisting of landform modifications (grading, trenching, and push piles) with many artifacts. (FSA, p. 4.3-8-10) This refuse resource is being treated as eligible for the NRHP and CRHR until such time that the research design, background research and analysis of artifacts is completed and the determination of eligibility can be clearly made. BEP II has agreed to restrict all activities, thus protecting the fenced-off refuse site. (FSA, p. 4.3-14)

Ethnic Heritage

Ethnographic resources are those resources important to the heritage of a particular ethnic or cultural group, such as Native Americans, Hawaiian, Eskimo, African, European, or Asian immigrants. They may include traditional resource collecting areas, ceremonial sites, topographic features, cemeteries, shrines, or ethnic neighborhoods and structures. Ethnographic resources also include personal biographical data, interview data, and collections or oral histories relating the life ways of previous generations.

Several ethnohistoric and contemporary Yuman- and Numic-speaking peoples trace heritage ties to the lower Colorado River region. Yuman groups included the Mojave, Quechan, Hualapai, Havasupai, Yavapai, Kamia, Maricopa, Halchidhoma, Cocopah, and Paipai. Numic groups include the Chemehuevi and the closely related Southern Paiute. Warfare and migration characterized this period and population boundaries shifted regularly. Before about 1700, the exact group occupying the project area is unknown but it is likely that it was the Maricopa. Sometime after 1700, the Halchidhoma settled the area, living tenuously between the powerful and militant Quechan to the south and the Mojave to the north.

Halchidhoma and Maricopa may be regarded as closely related; the two groups interacted extensively and spoke similar dialects. These two groups were also similar in many ways to the Quechan and the Mojave. The Quechan lived in dispersed rancherias along the Colorado River north and south of the confluence with the Gila River. Like the Mojave, large permanent semi-subterranean houses were occupied in the winter, and ramadas or brush shades were used in the summer. Under constant attack by the Quechan and Mojave, the Halchidhoma fled the area for northern Mexico and then the Gila River around 1828. The aggressive Mojave followed them into their former territory and occupied it briefly. The "core" area of the Mojave was the Mojave Valley but did extend north to Old Cottonwood Island, about 15 miles north of Davis Dam, and as far south as the Colorado River Indian Reservation when they were first encountered by the Juan de Oñate expedition in 1604. Occasionally and intermittently they controlled areas as far south as Palo Verde. The Mojave later invited another of their confederates, the Numic-speaking Chemehuevi, to settle the area.

The Chemehuevi (and Southern Paiute) were organized into small, mobile groups whose settlement patterns were influenced heavily by seasonal availability of plant resources. Chemehuevi groups moved throughout the desert to exploit plant resources as they became available. They fragmented into nuclear families when food was scant or dispersed but also came together on occasion for game drives. They resided in the Chemehuevi Valley and the Colorado River Valley by 1859. When Chemehuevi groups gained access to land on the Colorado River, they quickly adopted floodwater farming. This group dominated until displaced by Euro-American settlement.

The Halchidhoma, Maricopa, Mojave, Quechan, Chemehuevi, and other groups of the lower Colorado River region shared traits including patrilateral or bilateral descent, an emphasis on personal dreams, cremation of the dead, and floodwater agriculture. They typically lived in settlements widely scattered over the floodplain and adjacent low terraces of the Colorado River. Adjacent higher terraces were used for hunting and gathering wild desert foods.

Annual flooding deposited layers of rich silt and provided for the growing of crops such as maize, tepary beans, pumpkins, gourds, and sunflowers. Later, Euro-Americans introduced wheat, barley, muskmelons, and cowpeas. People relied to some extent on stored supplies of maize and beans, as well as wild foods of the desert. Important wild foods included mesquite, screwbean, tule roots and sprouts, chia, yucca fruits, and agave. Rabbits, squirrels, chipmunks, gophers, woodrats, quail, duck, mudhen, and pigeon were hunted for meat, as well as large game such as deer and mountain sheep. Fishing was also common in the late summer when the river receded.

In addition to local resources, people relied to some degree on regional exchange of goods. The Quechan traded pumpkins, beans, melons, gourds, and maize and received rabbit skin blankets, baskets, buckskins, mescal and finished leather goods from the Yavapai, woven blankets from the Hopi, acorns from the Kumeyaay and Cahuilla, eagle feathers from the Mojave, and tobacco from the Kamia or eastern Kumeyaay.

Yuman contact with Europeans first occurred in 1540 when Hernando de Alarcon sailed up the Colorado River to near present-day Yuma, Arizona. However, missions were not established in the region until the late eighteenth century. Once European settlement occurred, conflicts increased in scale and frequency.

Energy Commission staff contacted the Native American Heritage Commission (NAHC) to obtain a list of Native Americans to be contacted for the project area. The NAHC provided names of contacts for Riverside County. The Energy Commission sent letters to the individuals and tribes on the list from the NAHC requesting information regarding resources that could be impacted by the project and concerns regarding those possible impacts. No responses have been received.

An ethnographic study was provided to the Energy Commission in accordance with **CUL-15** of the BEP I amendment that added a 66-acre area for deposit of excess sediments. Five tribes agreed to participate in the study. The author of the ethnographic report states that it can be inferred that tribal comments are relevant to both phases of the Blythe Energy Projects, even though the questionnaire is directed at BEP I.

The Halchidhoma-Maricopa people have provided information that there may be burial and cremation sites in the vicinity of Palo Verde Mesa. The Quechan also identified this as an area where ceremonial activities take place. This study identifies the location of the Blythe Energy project as “clearly within a highly significant portion of the traditional Yuman, especially Quechan, cultural landscape.” The Quechan indicated that within the study area there are sacred areas where physical residues of human use or occupation may or may not be present. The Chemehuevi people regard this area as part of a landscape containing places, landmarks, natural geophysical features and sites that are important to their history and identity. They are concerned about preservation of land, plants, water, minerals and sacred places within this landscape. A portion of the Salt Song Trail crosses the Palo Verde Valley, and the physical trail route is considered sacred by some of the Chemehuevi. (FSA, pp. 4.3-10 & 11)

The ethnographic report indicated that sacred resources in the vicinity of the project would be impacted. Native Americans have provided recommendations regarding mitigation for the impact of the project on sacred resources. Native American tribes recommended that the five culturally affiliated Indian Tribes be allowed access to the BEP I and II sites for the purpose of allowing traditional leaders to bless the area and conduct the other appropriate ceremonies. They also recommended that the tribes continue to receive any and all information updates regarding any future planned activities related to the Blythe Energy Projects. This information would include any proposed expansion, construction, improvement, refurbishing, or other such activities that might result in an expansion of the project site boundaries. The recommendations also include other tribes that are likely to be indirectly affiliated with the BEP project areas, such as the Tukic-speaking Cahuilla groups, Yuman-speaking Cocopah, Kumeyaay, Pai, and Yavapai tribes, the Twenty-nine Palms Band of Mission Indians (Chemehuevi) and Maricopa members of the Gila River and Ak-Chin Pima-Maricopa Indian Community. (FSA, p. 4.3-15)

MITIGATION:

- ☑ The Project Owner will designate a cultural resource specialist who will monitor excavation and, in the event of an unanticipated discovery, provide for the handling and curation of any recovered cultural resources. Conditions: **CUL-1** through **CUL-7**.
- ☑ Given the proximity of the project to sacred Native American sites, the Project Owner shall invite tribal leaders to bless the project area and conduct other appropriate ceremonies. Condition: **CUL-9**

<u>Cumulative Impacts</u>

The potential for cumulative impacts may be associated with the degree of prehistoric and historic sensitivity. The project site is located in a general area where historic properties and archaeological sites have previously been identified.

The Imperial Irrigation District and the Bureau of Land Management are in the process of preparing a joint Final Environmental Impact Report/Environmental Impact Statement (FEIR/EIS) for an alternative transmission line between Blythe and either Palm Springs or Niland, both of which have large substation facilities. BEP I has also proposed the construction of a transmission line from the Buck Boulevard Substation to the Julian Hinds Substation and one from the Buck Boulevard Substation to the Midpoint Substation. Transmission lines would cross areas where many cultural resources exist. This could result in indirect impacts to resources. Impacts identified in the ethnographic report required for the BEP I project would be increased. The ethnographic report did discuss concerns over cumulative impacts. The recommendations for mitigation appear to address direct as well as cumulative impacts. (FSA, p. 4.3-16)

Finding

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to cultural resources and all potential cultural resource impacts will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

CUL-1 Prior to the start of ground disturbance, the project owner shall obtain the services of a Cultural Resources Specialist (CRS), and one or more alternates, if alternates are needed, to manage all monitoring, mitigation and curation activities. The CRS may elect to obtain the services of Cultural Resource Monitors (CRMs) and other technical specialists, if needed, to assist in monitoring, mitigation and curation activities. The project owner shall ensure that the CRS evaluates any cultural resources that are newly discovered or that may be affected in an unanticipated manner for eligibility to the California Register of Historic Resources (CRHR) and NRHP. No ground disturbance shall occur prior to CPM approval of the CRS, unless specifically approved by the CPM.

CULTURAL RESOURCES SPECIALIST

The resume for the CRS and alternate(s) shall include information demonstrating that the minimum qualifications specified in the U.S. Secretary of Interior Guidelines, as published in the Code of Federal Regulations, 36 CFR Part 61 are met. In addition, the CRS shall have the following qualifications:

a. The technical specialty of the CRS shall be appropriate to the needs of the project and shall include a background in anthropology, archaeology, history, architectural history or a related field; and

b. At least three years of archaeological or historic, as appropriate, resource mitigation and field experience in California.

The resume of the CRS shall include the names and telephone numbers of contacts familiar with the work of the CRS on referenced projects, and shall demonstrate that the CRS has the appropriate education and experience to accomplish the cultural resource tasks that must be addressed during ground disturbance, grading, construction and operation. In lieu of the above requirements, the resume shall demonstrate to the satisfaction of the CPM and Western that the proposed CRS or alternate has the appropriate training and background to effectively implement the conditions of certification.

CULTURAL RESOURCES MONITOR

CRMs shall have the following qualifications:

1. a BS or BA degree in anthropology, archaeology, historic archaeology or a related field and one year experience monitoring in California; or

2. an AS or AA degree in anthropology, archaeology, historic 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, historic archaeology or a related field and two years of monitoring experience in California.

CULTURAL RESOURCES TECHNICAL SPECIALISTS
The resume(s) of any additional technical specialists, e.g. historic archeologist, historian, architectural historian, physical anthropologist shall be submitted to the CPM for approval.

The project owner shall submit the resume for the CRS, and alternate(s) if desired, to the CPM for review and approval at least 45 days prior to the start of ground disturbance.

<u>Verification:</u> The project owner shall submit the resume for the CRS, and alternate(s) if desired, to the CPM for review and approval and to Western at least 45 days prior to the start of ground disturbance. At least 10 days prior to a termination or release of the CRS, the project owner shall submit the resume of the proposed new CRS to the CPM for review and approval and to Western.

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 resource monitoring required by this condition. If additional CRMs are obtained during the project, the CRS shall provide additional letters to the CPM and Western identifying the CRMs and attesting to the qualifications of the CRM, at least five days prior to the CRM beginning on-site duties. At least 10 days prior to beginning tasks, the resume(s) of any additional technical specialists shall be provided to the CPM for review and approval and to Western.

At least 10 days prior to the start of ground disturbance, the project owner shall confirm in writing to the CPM and to Western that the approved CRS will be available for on-site work and is prepared to implement the cultural resources conditions of certification.

CUL-2 Prior to the start of ground disturbance, the project owner shall provide the CRS, the CPM and Western with maps and drawings showing the footprint of the power plant and all linear facilities. Maps shall include the appropriate USGS quadrangles and a map at an appropriate scale (e.g., 1:2000 or 1" = 200') for plotting individual artifacts. 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 submittals and in consultation with the CRS approve those that are appropriate for use in cultural resources planning activities.
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 and Western.

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 and Western of any changes to the scheduling of the construction phases. No ground disturbance shall occur prior to CPM approval of maps and drawings, unless specifically approved by the CPM.

Verification:

1. The project owner shall submit the subject maps and drawings at least 40 days prior to the start of ground disturbance to the CPM and Western. 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 to the CPM and Western at least 15 days prior to start of ground disturbance for those changes.
3. If project construction is phased owner shall submit the subject maps and drawings, if not previously provided, 15 days prior to each phase to the CPM and Western.
4. A current schedule of anticipated project activity shall be provided to the CRS on a weekly basis during ground disturbance and also provided in each Monthly Compliance Report (MCR).
5. The project owner shall provide written notice of any changes to scheduling of construction phases within five days of identifying the changes to the CPM and Western.

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 the CRS, to the CPM for approval and to Western. The CRMMP shall identify general and specific measures to minimize potential impacts to sensitive cultural resources. Copies of the CRMMP shall reside with the CRS, alternate CRS, each monitor, and the project owner's on-site manager. No ground disturbance shall occur prior to CPM approval of the CRMMP, unless specifically approved by the CPM.

The CRMMP shall include, but not be limited to, the following elements and measures.

1. A proposed general research design for buried Native American deposits that includes a discussion of research questions and testable hypotheses applicable to the project area. A refined research design will be prepared for any resource where data recovery is required.
2. The following statement shall be added to the Introduction: Any discussion, summary, or paraphrasing of the conditions in this CRMMP is intended as general guidance and as an aid to the user in understanding the conditions and their implementation. If there appears to be a discrepancy between the conditions and the way in which they have been summarized, described, or interpreted in the CRMMP, the conditions, as written in the Final Decision, supersede any interpretation of the conditions in the CRMMP. (The Cultural Resources Conditions of Certification are attached as an appendix to this CRMMP.)

3. A discussion of the requirement that all cultural resources encountered shall be recorded on a DPR form 523 and mapped (may include photos). In addition, all archaeological materials collected as a result of the archaeological investigations shall be curated as specified in the research design in accordance with The State Historical Resources Commission's "Guidelines for the Curation of Archaeological Collections," into a retrievable storage collection in a public repository or museum. The public repository or museum must meet the standards and requirements for the curation of cultural resources set forth at Title 36 of the Federal Code of Regulations, Part 79.

4. A discussion of the availability and the designated specialist's access to equipment and supplies necessary for site mapping, photographing, and recovering any cultural resource materials encountered during construction.

<u>Verification:</u> The project owner shall submit the subject CRMMP at least 30 days prior to the start of ground disturbance to the CPM and Western. Per ARMR Guidelines the author's name shall appear on the title page of the CRMMP. Ground disturbance activities may not commence until the CRMMP is approved, unless specifically approved by the CPM. A letter shall be provided to the CPM indicating that the project owner would pay curation fees for any materials collected as a result of the archaeological investigations (survey, testing, data recovery).

CUL-4 The project owner shall submit the Cultural Resources Report (CRR) to the CPM for approval and to Western. The CRR shall be written by the CRS and shall be provided in the ARMR format. The CRR shall report on all field activities including dates, times and locations, findings, samplings and analysis. All survey reports, Department of Parks and Recreation (DPR) 523 forms and additional research reports not previously submitted to the California Historic Resource Information System (CHRIS) and the State Historic Preservation Officer (SHPO) shall be included as an appendix to the CRR.

<u>Verification:</u> The project owner shall submit the subject CRR within 90 days after completion of ground disturbance (including landscaping) to the CPM and Western. Within 10 days after CPM approval, the project owner shall provide documentation to the CPM that copies of the CRR have been provided to the SHPO, the CHRIS and the curating institution (if archaeological materials were collected).

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 involved in ground disturbance within their first week of employment. The training may be presented in the form of a video. 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. Information that the CRS, alternate CRS, and CRMs have the authority to halt construction to the degree necessary, as determined by the CRS, in the event of a discovery or unanticipated impact to a cultural resource;
4. 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;
5. An informational brochure that identifies reporting procedures in the event of a discovery;
6. An acknowledgement form signed by each worker indicating that they have received the training; and
7. 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 specifically approved by the CPM.

Verification: The project owner shall provide in the Monthly Compliance Report the WEAP Certification of Completion form of persons 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 shall monitor ground disturbance of previously undisturbed sediments full time in the vicinity of the project site, linear facilities and ground disturbance at laydown areas or 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. In the event that the project owner determines that full-time monitoring is not necessary in certain locations, a letter or e-mail providing a detailed justification for the decision to reduce the level of monitoring shall be provided to the CPM for review and approval and to Western prior to any reduction in monitoring.

CRMs shall keep a daily log of any monitoring or cultural resource activities and the CRS shall prepare a weekly summary report on the progress or status of cultural resources-related activities. The CRS may informally discuss cultural resource monitoring and mitigation activities with Energy Commission technical staff.

The CRS and the project owner shall notify the CPM and Western by telephone or e-mail of any incidents of non-compliance with the conditions of certification and/or applicable LORS upon becoming aware of the situation. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the conditions of certification.

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 of certification.

A Native American monitor shall be obtained to monitor excavations in undisturbed sediments in areas where Native American artifacts are discovered. Informational lists of concerned 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.

Verification: During the ground disturbance phases of the project, if the CRS wishes to reduce the level of monitoring occurring at the project, a letter or e-mail identifying the area(s) where the project owner recommends the reduction and justifying the reductions in monitoring shall be submitted to the CPM for review and approval and to Western. Documentation justifying a reduced level of monitoring shall be submitted to the CPM and Western at least 24 hours prior to the date of planned reduction in monitoring. The project owner, the CRS, the CPM and Western will meet to discuss the monitoring requirements prior to the approval of any reduction in monitoring.

During the ground disturbance phases of the project, the project owner shall include in the MCR to the CPM copies of the weekly summary reports prepared by the CRS regarding project-related cultural resources monitoring. Copies of daily logs shall be retained and made available for audit by the CPM and Western.

Within 24 hours of recognition of a non-compliance issue with the conditions of certification and/or applicable LORS, the CRS and the project owner shall notify the CPM and Western by telephone of the problem and of steps being taken to resolve the problem. The telephone call shall be followed by an e-mail or fax detailing the non-compliance issue and the measures necessary to achieve resolution of the issue. Daily logs shall include forms detailing any instances of non-compliance. In the event of any non-compliance issue, a report written no sooner than two weeks after resolution of the issue that describes the issue, resolution of the issue and the effectiveness or the resolution measures, shall be provided in the next MCR.

If Native American artifacts are discovered in undisturbed sediments, the project owner shall send notification within one week to the CPM and Western identifying the person(s) retained to conduct Native American monitoring. The project owner shall also provide a plan identifying the proposed monitoring schedule and information explaining how Native Americans who wish to provide comments will be allowed to comment. 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.

CUL-7 The project owner shall grant authority to halt construction to the CRS, alternate CRS and the CRMs in the event previously unknown cultural resource sites or materials are encountered, or if known resources may be impacted in a previously unanticipated manner (discovery). Redirection of ground disturbance shall be accomplished under the direction of the construction supervisor in consultation with the CRS.

In the event cultural resources are found or impacts can be anticipated, the halting or redirection of construction shall remain in effect until all of the following have occurred:

1. The CRS has notified the project owner, and the CPM and Western have 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 eligibility and recommendations for mitigation of any cultural resources discoveries whether or not a determination of significance has been made.
2. The CRS and the project owner have consulted with the CPM and Western, and the CPM and Western have concurred with the recommended eligibility of the discovery and proposed data recovery or other mitigation; and
3. Any necessary data recovery and mitigation has been completed.

Verification: At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM, Western and CRS with a letter confirming that the CRS, alternate CRS and CRMs have the authority to halt construction activities in the vicinity of a cultural resource discovery, and that the project owner shall ensure that the CRS notifies the CPM and Western 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.

CUL-8 The project owner or its agents shall not conduct any activities within the fenced portion of CA-RIV-6370H or remove any portion of the fence without approval of the CPM. Any contract or agreement to purchase any interest in the project (or land identified in the AFC as the project area) must include a clause obligating the successor in interest to the terms of the Memorandum of Agreement between Western and the CA SHPO.

Verification: The project owner shall make a statement in each Monthly Compliance Report during construction and in each Annual Compliance Report during operation regarding the condition of the fence surrounding CA-RIV-6370H, the condition of the site and the project's compliance with this condition.

CUL-9 The project owner shall invite tribal leaders, elders and/or representatives of the Salt River Pima-Maricopa Indian Community, the Fort Yuma Quechan Tribe, the Chemehuevi Indian Tribe and the Fort Mojave Indian Tribe to bless the project area and conduct other appropriate ceremonies. As recommended in "Blythe Energy Projects American Indian Ethnographic Assessment Study, Final Report," participants shall be provided with adequate compensation in the form of a consulting fee and reimbursement for travel, meal and lodging costs, if lodging is necessary. Members of the Tukic-speaking Cahuilla groups, Yuman-speaking Cocopah, Kumeyaay, Pai, and Yavapai tribes, the Twenty-nine Palms Band of Mission Indians (Chemehuevi) and Maricopa members of the Gila River and Ak-Chin Pima-Maricopa Indian Community shall also be notified of the site visit and invited to attend and conduct appropriate ceremonies. The project owner shall also invite Western's Historic

Preservation Officer, the CPM and City of Blythe officials to the blessing. The date(s) for the blessing and ceremonies shall be prior to ground disturbing activities or at a time mutually convenient to the tribes, project owner, Western's Historic Preservation Officer, the CPM and the City of Blythe officials.

Verification: At least 30 days prior to ground disturbing activities, the project owner shall provide copies of the invitation letters to the CPM. If additional time and correspondence is required to arrive at a mutually convenient time, copies of all correspondence to finalize the blessing/ceremonies date shall be provided to the CPM. Within 10 days of the blessing ceremony, the project owner shall provide a list of attendees to the CPM.

If the tribes indicate that they are not interested in the blessing ceremony, the project owner shall, prior to ground disturbance, provide to the CPM for review and Western copies of telephone logs and correspondence with the aforementioned tribes documenting that the tribes have declined to accept the offer for the blessing ceremony. Within 15 days of CPM acceptance of the documentation demonstrating that the ceremony is not desired, the project owner shall provide a letter to all parties listed in this condition notifying them that the ceremony is no longer desired.

CUL-10 The project owner shall provide copies to the CPM of documents submitted to Western for compliance with Section 106 of the National Historic Preservation Act. If the project owner becomes a signatory to the Memorandum of Agreement (MOA) for the BEP I project, then correspondence regarding compliance with the stipulations of that agreement shall be provided to the CPM.

Verification: Within 15 days after documents are provided to Western for their compliance with the NHPA, the project owner shall provide copies of the correspondence to the CPM. If the project owner becomes a signatory to the MOA for the BEP I project, correspondence regarding compliance with the stipulation shall be provided in the next Monthly Compliance Report.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

CULTURAL RESOURCES

APPLICABLE LAW	DESCRIPTION
FEDERAL	
National Historic Preservation Act 916 USC 470, et seq.)	Applicable if federal permits are required, Federal funding provided, or lands owned by Federal government. Requires consultation with lead Federal agency, SHPO, & Advisory Council on Historic Preservation.
36 CFR 61	Professional qualification standards/procedures for state and local government historic preservation programs/cultural resources management.
STATE	
California Environmental Quality Act (CEQA) Guidelines (Sections 15064.5 & 15126.4)	Construction may encounter archaeological resources.
Health & Safety Code 7050.5	If potential Native American human remains are encountered, coroner notifies Native American Heritage Commissioner within 24 hours.
Public Resources Code Section 5097.9	If Native American human remains are encountered, the Native American Heritage Commissioner assigns Most Likely Descendent.

GEOLOGY – Summary of Findings and Conditions

Earthquake	**CONDITIONS**	**None**	**YES**
	Seismic zone 3 conditions at the project site require the preparation of an Engineering Geology Report to characterize the geologic conditions. **CONDITIONS:** ☑ The Project Owner shall prepare an Engineering Geology Report pursuant to the California Building Standards Code to fully describe the geologic conditions of the power plant site and, if necessary, shall modify plans to address adverse soil or geologic conditions. Conditions: **GEN-1, CIVIL-1** & **CIVIL-2**.		
Instability	**None**	**None**	**YES**
	With a water table greater than 50 feet in depth, there is no potential for liquefaction. Since the plant site is generally underlain by medium dense to dense silty sand, the potential for either hydrocompaction or expansive soils is low. The potential for ground subsidence is low because BEP II operations are not anticipated to cause a significant drawdown of the water table. The BEP II site is relatively flat, so the potential impact of landslides to the BEP II site is low. There is a low probability for a debris-flow driven by a flash flood caused by an unusually intense thunderstorm.		
Mineral Resources	**None**	**None**	**YES**
	There are no known geologic resources at the power plant site.		
Fossils (Paleontology)	**MITIGATION**	**None**	**YES**
	There are no known paleontological resources at the power plant site. Procedures need to be in place in the event of an unanticipated discovery of paleontological resources during site excavation. **MITIGATION:** ☑ Procedures for the recovery of unknown paleontological resources at the power plant site will prevent a significant impact to paleontological resources. Conditions: **PAL-1** to **PAL-7**.		
Flood	**None**	**None**	**YES**
	There is some potential for a debris-flow driven by a flash flood; however, the flash flood would be caused by an unusually intense thunderstorm, which would be a low probability event.		

GEOLOGY – GENERAL

The proposed BEP II site is located within the Colorado Desert geomorphic province near the Colorado River and the California – Arizona state line. This area within the Colorado Desert is characterized by the flood plain of the Colorado River and numerous flood terraces. The BEP II site is located on the Palo Verde Mesa, a flood terrace of the Colorado River. Major geologic units in the vicinity of the site include Tertiary and pre-Tertiary igneous, metamorphic, and sedimentary bedrock, Miocene to Pliocene fanglomerate [conglomerate], the Pliocene Bouse Formation, and Quaternary alluvium. The Pliocene to Pleistocene alluvium is also named the Chemehuevi Formation. The Miocene to Pliocene fanglomerate consists of cemented, poorly sorted gravel and sand. The Pliocene Bouse Formation consists of marine and brackish-water limestone and interbedded clays, silts, sands, and tufa (chemical sedimentary rock consisting of calcium carbonate or silica, deposited in solution in the water of a lake). The Quaternary alluvium consists of sands, gravels, silts, and clays.

The plant site has received approximately 200,000 cubic yards of fill, the result of mass grading during BEP I construction. Underlying native materials consist of a mix of light to dark brown, medium dense to dense silty sand to poorly-graded sand to a depth of 111 feet. Information contained in the AFC indicates ground water is present at a depth approximately 88-1/2 feet below the original ground surface. (FSA, p. 5.2-1 & 2.)

Earthquake

The project is located within Seismic Zone 3 per the 2001 edition of the California Building Standards Code. The closest known Holocene (active) faults are the Brawley Fault, Elmore Ranch Fault, and the San Andreas Fault (Southern and Coachella segments), which is the closest to the project and located approximately 61 miles southwest of the plant site. (FSA, p. 5.2-3)

To fully describe the geologic conditions of the power plant site, the Project Owner shall prepare an Engineering Geology Report pursuant to the California Building Standards Code. During site grading, a designated Engineering Geologist shall monitor for any adverse soil or geologic conditions. Conditions: **GEN-1, CIVIL-1** and **CIVIL-2.**

CONDITIONS:

- ☑ The Project Owner shall prepare an Engineering Geology Report pursuant to the California Building Standards Code to fully describe the geologic conditions of the power plant site and, if necessary, shall modify plans to address adverse soil or geologic conditions. Conditions: **GEN-1, CIVIL-1** & **CIVIL-2**.

Instability

Liquefaction is a nearly complete loss of soil shear strength that can occur during a seismic event. During the seismic event, cyclic shear stresses cause the development of excessive pore water pressure between the soil grains, effectively reducing the internal strength of the soil. This phenomenon is generally limited to unconsolidated, clean to silty sand (up to 35 percent non-plastic fines) and very soft silts lying below the ground water table. The higher the ground acceleration caused by a seismic event, the more likely liquefaction is to occur. Severe liquefaction can result in catastrophic settlements of overlying structural improvements and lateral spreading of the liquefied layer when confined vertically but not horizontally.

As reported in the AFC, ground water was encountered during exploration at a depth approximately 88-1/2 feet below the ground surface at the plant site. Soils encountered during this exploration generally consist of medium dense to dense silty sand. With a water table greater than 50 feet in depth, there is no potential for liquefaction. (FSA, p. 5.2-4)

Hydrocompaction is the process of the loss of soil volume upon the application of water. Since the plant site is generally underlain by medium dense to dense silty sand, the potential for hydrocompaction at the plant site is low. (FSA, p. 5.2-4)

Subsidence of surface and near-surface soils may be induced at the site by either strong ground shaking due to a large nearby earthquake, by consolidation of loose or soft soils due to heavy loading of the soils by large structures, or by the extraction of fluids from the subsurface. The BEP II will obtain ground water from wells located at the plant site with drawdowns estimated to be less than 4 feet; as such, significant drawdown of the water table due to BEP II operations is not anticipated. As a result, the potential for ground subsidence is low. (FSA, p. 5.2-4)

Soils that contain a high percentage of expansive clay minerals are prone to expansion if subjected to an increase in water content. Expansive soils are usually measured with an index test such as the expansive index potential. As reported in the AFC, materials encountered in the project area consist of silty sand soils. As a result, the potential for expansive soils is low. (FSA, p. 5.2-4)

Landslides typically involve rotational slump failures within surface soils/colluviums and/or weakened bedrock that are usually implemented by an increase of the material's moisture content above a layer which exhibits a relatively low strength. Debris-flows are shallow landslides that travel down-slope very rapidly as muddy slurry. The BEP II site is relatively flat with up to approximately 25 feet of relief over the plant site and lies approximately 1 mile west of the edge of the Palo Verde Mesa. As a result, the potential impact of landslides to the BEP II site is low. There is some potential for a debris-flow driven by a flash flood; however, the flash flood would be caused by an unusually intense thunderstorm, which would be a low probability event. (FSA, p. 5.2-5)

Mineral Resources

Energy Commission staff have reviewed applicable geologic maps and reports for this area. Based on this information and the AFC, there are no known mineral resources located at or immediately adjacent to the proposed BEP II site. An area of undeveloped warm thermal waters and several thermal wells are present in the Palo Verde Valley to the east. No other geologic resources are located at or immediately adjacent to the proposed BEP II site. (FSA, p. 5.2-5)

Fossils – Paleontology

Energy Commission staff has reviewed the Applicant's paleontological resources technical report. The Applicant's consultant conducted a paleontologic resources field survey and a sensitivity analysis for the BEP I and BEP II plant sites. No significant fossil fragments were observed at the BEP II site; however, two vertebrate fossils were identified during construction of the BEP I project over five months of near-full-time monitoring. Surficial, older alluvium of the Chemehuevi Formation has been assigned a "high" sensitivity rating with respect to potentially containing paleontological resources. Based on this information and Staff's review of available information, the proposed BEP II site has a high potential to contain significant paleontologic resources. (FSA, p. 5.2-6.)

Since the project will include significant amounts of trenching and grading, and a few fossils have been discovered at the adjacent BEP I plant site, paleontologic resources will likely encountered during trenching and possibly mass grading of undisturbed areas at the BEP II site. Conditions **PAL-1** to **PAL-7** will mitigate any paleontological resource impacts to a less than significant level. (FSA, p. 5.2-6)

MITIGATION:

- ☑ Procedures for the recovery of unknown paleontological resources at the power plant site will prevent a significant impact to paleontological resources. Conditions: **PAL-1** to **PAL-7**.

Floods

A tsunami is a wave of water that may be generated by an earthquake or a large underwater landslide. The proposed site is situated approximately 350 to 375 feet above mean sea level, and no large bodies of water are present near the BEP II site. As a result, the potential for tsunamis to affect the site is negligible. (FSA, p. 5.2-5)

Cumulative Impacts

The BEP II site lies in an area that exhibits low geologic hazards and no known geologic or mineral resources. However, operation of the BEP II project at full capacity will require a new electrical transmission line linking a new substation near the BEP I site with the Southern California Edison Company's Devers Substation, located near Palm Springs, California.

The Bureau of Land Management (BLM) has recommended a specific measure to mitigate paleontological impacts associated with the transmission line over federally administered land. The mitigation measure requires that a paleontologist develop a mitigation program. The potential for significant adverse cumulative impacts to the project from geologic hazards, and to potential geologic, mineralogic, and paleontologic resources from the proposed project is not significant. (FSA, p. 5.2-6.)

Findings

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to geological and paleontological resources, all potential adverse impacts to geologic and paleontological resources will be mitigated to insignificance, and the public is not exposed to geological hazards.

CONDITIONS OF CERTIFICATION

Conditions of Certification with respect to Geology are covered under Conditions of Certification **GEN-1**, **GEN-5**, and **CIVIL-1** in the **FACILITY DESIGN** section. Paleontological Conditions of Certification **PAL-1 through PAL-7** are identified below.

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 submit to the CPM to keep on file, resumes of the qualified Paleontological Resource Monitors (PRMs). If a PRM is replaced, the resumes 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:

- Institutional affiliations, appropriate credentials and college degree;
- ability to recognize and collect fossils in the field;
- local geological and biostratigraphic expertise;
- proficiency in identifying vertebrate and invertebrate fossils and;
- 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 oversee and evaluate project operations as he or she deems necessary. Paleontologic resource monitors (PRMs) shall have the equivalent of the following qualifications:

BS or BA degree in geology or paleontology and one year 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: 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. 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 and 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 beginning on-site duties. 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 laydown 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 the plan and profile drawings for the utility lines would be acceptable for this purpose. The plan drawings shall show the location, depth, and extent of all ground disturbances and should be of such as scale to allow the PRS to determine and map fossil occurrences. If the footprint of the power plant or linear facility changes, the project owner shall provide maps and drawings reflecting these changes to the PRS and CPM.

If construction of the project will proceed 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. Prior to work commencing 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 during the next week, until ground disturbance is completed.

Verification: 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. 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. 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 a basis for discussion in the event that 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 the 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. A discussion of the locations of where the monitoring of project construction activities is deemed necessary, and a proposed schedule for the monitoring and sampling;
5. A discussion of the procedures to be followed in the event of a significant fossil discovery, halting construction, resuming construction, and how notifications will be performed;
6. 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;
7. Procedures for inventory, preparation, and delivery for curation into a retrievable storage collection in a public repository or museum, which meets the Society of Vertebrate Paleontology standards and requirements for the curation of paleontological resources;
8. Identification of the institution that has agreed to receive any 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
9. A copy of the paleontological Conditions of Certification.

<u>Verification:</u> At least (30) days prior to ground disturbance, the project owner shall provide two copies 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, the project owner and the PRS shall prepare and conduct weekly CPM-approved training for all recently employed project managers, construction supervisors and workers who are involved with or operate ground disturbing equipment or tools and who have not previously had the training. 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 any other areas of interest or concern.

The Worker Environmental Awareness Program (WEAP) shall address the potential to encounter paleontological resources in the field, the sensitivity and importance of these resources, and the legal obligations to preserve and protect such 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 shall be provided for project sites containing units of high 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 Certification of Completion of WEAP form signed by each worker indicating that they have received the training; and
7. A sticker that shall be placed on hard hats indicating that environmental training has been completed.

<u>Verification:</u> At least 30 days prior to ground disturbance, the project owner shall submit two copies of the proposed WEAP including the brochure with the set of reporting procedures the workers are to follow. 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 on using a video for interim training.

If the project owner requests an alternate paleontological trainer, the project owner shall submit the resume and qualifications of the trainer to the CPM for review and approval prior to installation of the alternate trainer. Alternate trainers shall not conduct training prior to CPM authorization.

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 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 consistently with the PRMMP all construction-related grading, excavation, trenching, and augering in previously undisturbed materials where potentially fossil-bearing materials have been identified. 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 different from the accepted program presented 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. 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) keeps a daily log of monitoring 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 immediately notifies the CPM 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 immediately (no later than the following morning after the find, or Monday morning in the case of a weekend) of any halt of construction activities.

The project owner shall ensure that the PRS prepares a summary of the monitoring and other paleontological activities that will be placed in the Monthly Compliance Reports (MCR). 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, etc. A section of the report shall include the geologic units or subunits encountered; descriptions of sampling within each unit; and a list of identified fossils. A final section of the report shall address any issues or concerns about the project relating to paleontologic monitoring including any incidents of non-compliance and 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 the project construction.

Verification: The project owner shall maintain in their 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 completion and approval of the CPM-approved Paleontological Resource Report (See **PAL-7**). A signed contract or agreement with the PRS shall be provided to the CPM upon request. The project owner shall be responsible to pay 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 submitted 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.

Verification: Within (90) days after completion of ground disturbing activities, including landscaping, the project owner shall submit the Paleontological Resources Report under confidential cover to the CPM.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

GEOLOGY

APPLICABLE LAW	DESCRIPTION
FEDERAL	
There are no Federal LORS related to geological hazards and resources.	N/A
STATE	
California Building Standards Code (2001)	Specifies acceptable design criteria for storage and open excavation with respect to seismic design and load-bearing capacity.
LOCAL	
No local LORS related to geologic hazards and resources.	N/A

PALEONTOLOGICAL RESOURCES

APPLICABLE LAW	DESCRIPTION
FEDERAL	
There are no applicable LORS for this section.	
STATE	
California Environmental Quality Act	Defines significant impacts on a fossil site. Project construction might encounter fossil site/remains.
Public Resource Code Section 5097.5	Defines any unauthorized disturbance or removal of fossil site/remains on public land as a misdemeanor. Project construction might encounter fossil site/remains; construction workers might remove fossil remains.
Warren-Alquist Act	Requires CEC to evaluate energy facility siting in unique areas of scientific concern. Project construction might encounter fossil site/remains.
LOCAL	
There are no applicable LORS for this section.	

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HAZARDOUS MATERIALS – Summary of Findings and Conditions

<table>
<tr><td rowspan="2">Transportation</td><td>MITIGATION</td><td>None</td><td>YES</td></tr>
<tr><td colspan="3"><u>Construction</u>: Hazardous materials delivered during construction will be limited to gasoline, diesel fuel, motor oil, hydraulic fluid, solvents, cleaners, sealants, welding flux, lubricants, paint and paint thinner. No acutely hazardous materials will be transported to the power plant site.

<u>Operation</u>: There would be about 9 tanker truck deliveries of aqueous ammonia per month (approximately 108 per year), each delivering about 5,000 gallons. During the 30-year life of the project, a total of 9 deliveries of the more hazardous anhydrous ammonia would occur. Deliveries of hazardous materials are over pre-arranged routes selected for their safety features, including the absence of obstructions and curves, and minimal railroad traffic.

MITIGATION:
☑ Hazardous materials haulers must be specially licensed by the California Highway Patrol. Condition: TRANS–3; see also TRAFFIC & TRANSPORTATION section.
☑ The Project Owner shall implement a Safety Management Plan for the delivery of aqueous ammonia. Condition: HAZ-3.
☑ The Project Manager shall direct all hazardous materials deliveries over approved routes selected for safety. Condition: HAZ-7.</td></tr>
</table>

Storage & Use	**MITIGATION**	**None**	**YES**
	Construction: No acutely hazardous materials related to construction will be used or stored on-site at the power plant. Some materials designated as hazardous such as gasoline, diesel fuel, motor oil, hydraulic fluid, solvents, cleaners, sealants, welding flux, lubricants, paint and paint thinner will be used at the construction-site. Given the nature of these substances, the risk of off-site exposure is insignificant. Operation: Hazardous and acutely hazardous material, such as anhydrous ammonia, aqueous ammonia, and natural gas will be used for power plant operation. Tank ruptures or delivery spills are the only means by which there will be off-site exposure of on-site anhydrous ammonia or aqueous ammonia. The Project Owner will prepare a Hazardous Materials Management Plan and a Risk Management Plan to prevent releases of hazardous materials. Natural gas is currently delivered to the existing BEP I by a pipeline that will be extended to BEP II. Natural gas will not be stored on-site. **MITIGATION:** ☑ The Project Owner shall not store or use amounts of acutely hazardous materials in excess of proposed quantities. Condition: **HAZ–1** ☑ The Project Owner shall implement a Hazardous Materials Management Plan and Risk Management Plan. Condition: **HAZ-2**. ☑ The Project Owner shall implement an Ammonia Refrigeration Hazard Reduction Plan consistent with U.S. EPA guidelines. Condition: **HAZ-8**. ☑ The Project Owner shall install an automatic fire suppression system and door closures in the ammonia refrigeration plant. Condition: **HAZ-10**. ☑ The Project Owner shall install remotely readable sensors in the anhydrous ammonia containment building. Condition: **HAZ-11**.		
Disposal	**Insignificant**	**None**	**YES**
	The Project Owner shall implement a comprehensive program to manage wastes in accordance with state and federal regulations. Hazardous wastes will be collected by a licensed hazardous waste hauler and disposed of at a hazardous waste facility. (See **WASTE MANAGEMENT** section.)		

HAZARDOUS MATERIALS – GENERAL

The purpose of this analysis is to determine if the proposed project will cause a potential significant impact on the public as a result of the transportation, use, handling, storage, or disposal of hazardous materials at the proposed facility.

Aqueous ammonia (19.5 to 30 percent ammonia in aqueous (water) solution) and anhydrous ammonia are the only acutely hazardous materials proposed to be used or stored at the BEP II in quantities exceeding the reportable amounts defined in the California Health and Safety Code, section 25532 (j). Aqueous ammonia would be used for controlling oxides of nitrogen (NO_x) emissions through selective catalytic reduction and for condensate pH control. Anhydrous ammonia will be used in the inlet chilling system.

BEP II has proposed to use anhydrous ammonia as a refrigerant for an inlet chilling system. This system would use approximately 5,400 pounds of anhydrous ammonia circulating in a closed loop system. The use of a closed system would avoid refrigerant exposure to atmospheric conditions and would obviate the need for routine deliveries because losses would be minimal. Anhydrous ammonia is stored as a liquefied gas at elevated pressure and high internal energy that can act as a driving force in an accidental release, thus rapidly introducing large quantities of the material to the ambient air and resulting in high down-wind concentrations.

Other hazardous materials, such as mineral and lubricating oils, corrosion inhibitors and water conditioners, will be present at the proposed facility. Hazardous materials used during the construction phase include gasoline, diesel fuel, oil, welding gases, lubricants, solvents and paint. No acutely toxic hazardous materials will be used onsite during construction. None of these materials pose significant potential for off-site impacts as a result of the quantities on-site, their relative toxicity, their physical state, and/or their environmental mobility. Although no natural gas is stored, the project will also involve the handling of large amounts of natural gas. Natural gas poses some risk of fire. BEP II will tap into the natural gas line constructed for the existing BEP I and therefore would not require the construction of a new gas pipeline. This line supplies natural gas from the El Paso Natural Gas Terminal on the Arizona side of the Colorado River. (FSA, p. 4.4-1)

This analysis does not address potential exposure of workers to hazardous materials used at the proposed facility. (See **WORKER SAFETY**.) There are specific regulations applicable to protection of workers in general. The standards for exposure and methods used to protect workers are very different from those applicable to the general public. Employers must inform employees of hazards associated with their work and workers accept a higher level of risk than the general public in exchange for compensation. Workers are thus not afforded the same level of protection normally provided to the public. Further, special protective equipment and training can be used to protect workers and reduce the potential for health impacts associated with the handling of hazardous materials. Application of this type of mitigation would not be appropriate for the general public.

For additional information regarding hazardous materials transportation, see **TRAFFIC & TRANSPORTATION.** For additional information on hazardous waste disposal, see **WASTE MANAGEMENT**.

Transportation

Hazardous materials, including anhydrous and aqueous ammonia, sulfuric acid, and cleaning chemicals, will be transported to the facility via tanker truck. While many types of hazardous materials will be transported to the site, Staff believes that transport of aqueous ammonia poses the predominant risk associated with hazardous materials transport due its volatility and frequency of delivery. Anhydrous ammonia will be used as the refrigerant. This hazardous material will be transported to the site for the initial charging of the refrigeration system, again every four to five years to recharge the system after small losses, and possibly once more to drain and completely refill the system. Although only a very small amount of anhydrous ammonia would be used at BEP II to recharge the inlet chiller system (~300 pounds) every 4 - 5 years, the tanker truck transporting the ammonia to BEP II would be just one of several deliveries to other locations. Thus, the tanker truck could contain varying amounts of anhydrous ammonia up to the tanker volume of 30,000 pounds.

During the initial charge and the possible drain and recharge, a tanker loaded with approximately 5,400 pounds would be required. Thus, during the 30-year life of the project, a total of nine (9) deliveries of anhydrous ammonia could occur. Staff has previously found in other siting cases that this small number of trips would present an insignificant risk of accidental release to the public. Furthermore, the same on-site precautions and training for the use of anhydrous ammonia in the refrigeration system and the same off-site emergency response capabilities would be more than adequate to address and respond to any accidental release from these occasional tanker truck deliveries. Staff therefore believes that the transport of anhydrous ammonia to the facility for use as a refrigerant would present an insignificant risk, certainly much less than that presented and assessed for the multiple deliveries of aqueous ammonia. (FSA, p. 4.4-15)

Staff reviewed the Applicant's proposed transportation routes for hazardous materials delivery. Ammonia can be released during a transportation accident, and the extent of impact in the event of such a release would depend on the location of the accident and on the rate of dispersion of ammonia vapor from the surface of the aqueous ammonia pool. The likelihood of an accidental release during transport is dependent on 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 highway (I-10, US-95 or SR-78). Staff believes that it is appropriate to rely on the extensive regulatory program that applies to shipment of hazardous materials on California highways to ensure safe handling in general transportation. These regulations also address the issue of driver competence.

To address the issue of tank truck safety, aqueous ammonia will be delivered to the proposed facility in Department of Transportation (DOT) certified vehicles with design capacity of 6,000 gallons. These vehicles will be designed to DOT Code MC-307. These are high integrity vehicles designed for hauling of caustic materials such as ammonia. Condition **HAZ-8** ensures that delivery will be made in a tanker truck that meets or exceeds the specifications described by these regulations, regardless of which vendor supplies the aqueous or anhydrous ammonia.

To address the issue of accident rates, Staff reviewed the technical and scientific literature on hazardous materials transportation (including tanker trucks) accident rates in the United States and California. The maximum usage of aqueous ammonia each year of operation of the proposed BEP II will require about 9 tanker truck deliveries of aqueous ammonia per month (approximately 108 per year) each delivering about 5,000 gallons. Each delivery will travel approximately 2.5 miles between I-10 and the facility per delivery along Neighbors Boulevard to Hobsonway to Buck Boulevard to the facility (the shortest and most direct way). The result is about 270 miles of delivery tanker truck travel in the project area per year. Staff believes that the risk over this distance is insignificant. Data from the U.S. DOT show that the actual risk of a fatality over the past five years from all modes of hazardous material transportation (rail, air, boat, and truck) is approximately 0.1 in one million.

Staff therefore believes the risk of exposure to significant concentrations of aqueous ammonia during transportation to the facility is insignificant because of the remote possibility of accidental release of a sufficient quantity to present a danger to the public. The transportation of similar volumes of hazardous materials on the nation's highways is not unique nor an infrequent occurrence. Staff's analysis of the transportation of aqueous ammonia to the proposed facility (along with data from the U.S. DOT) demonstrates that the risk of accident and exposure is less than significant.

Based on the environmental mobility, toxicity, quantities present at the site and frequency of delivery, it is staff's opinion that aqueous ammonia poses the predominate risk associated with hazardous materials transportation and use at the proposed facility. Based on this, Staff concludes that the risk associated with transportation of other hazardous materials to the proposed facility does not significantly increase the risk of impact beyond that associated with ammonia transportation. (FSA, p. 4.4-16 & 17)

MITIGATION:

- ☑ Hazardous materials haulers must be specially licensed by the California Highway Patrol. Condition: **TRANS–3;** see also **TRAFFIC & TRANSPORTATION** section.
- ☑ The Project Owner shall implement a Safety Management Plan for the delivery of aqueous ammonia. Condition **HAZ-3**.
- ☑ The Project Owner shall direct all vendors delivering aqueous ammonia to use tanker trucks meeting or exceeding federal Department of Transportation crash-worthiness regulations. Condition **HAZ-6**.
- ☑ The Project Manager shall direct all hazardous materials deliveries over approved routes selected for safety. Condition **HAZ-7**.

Storage & Use

Provisions of California Health and Safety Code, section 25500 et seq., direct facility owners that store or handle acutely hazardous materials in excess of threshold quantities to develop a Risk Management Plan (RMP) and submit it to appropriate local authorities, the US EPA, and the designated local Administering Agency for review and approval. The plan must include an evaluation of the potential impacts associated with an accidental release, the likelihood of an accidental release, the magnitude of potential human exposure, any preexisting evaluations or studies of the material, and the accident history of the material. This new, recently developed program supersedes the California Risk Management and Prevention Plan (RMPP) and is called the California Accidental Release Prevention Program (CalARP).

The only hazardous materials proposed for use at the project in quantities exceeding the threshold amount are anhydrous ammonia and aqueous ammonia. (AFC p. 5.15-11).

Anhydrous Ammonia

Anhydrous ammonia is to be used as a refrigerant in the inlet air chiller system. The use of anhydrous ammonia can result in the formation and release of a gaseous cloud in the event of a release, even without interaction with other chemicals. This is a result of its relatively high vapor pressure and the large amounts of anhydrous ammonia that will be used in the closed loop cooling system. Anhydrous ammonia is a gas at ambient temperature but in many parts of the refrigerating system would exist as a liquid under high pressure. The rupture of a pipe or valve in the chilling system would likely result in a release of a mixture of ammonia vapor and very fine liquid droplets. The result of such a release would be a denser-than-air mixture that would create a vapor cloud. If a release occurred in other parts of the refrigerating system where ammonia is in the pure vapor phase, the ammonia would be less dense than air, would release at a faster rate, and would not form a vapor cloud.

The anhydrous ammonia will be kept in a closed loop system that will have no contact with the outside atmosphere. More importantly, the Applicant is proposing to use an indirect anhydrous ammonia chiller system that uses only about 15% of the normal volume of anhydrous ammonia such as that currently used at the BEP I power plant. This significantly lower volume reduces the risk of using this acutely hazardous material. (FSA, p. 4.4-7)

Piping of the chilling system will be welded construction with minimal flanged connections to minimize the potential for spills. Safety controls such as ammonia detection equipment, alarms and an automatic shutdown system would be installed in the equipment enclosures. Additionally, an automatic fire suppression system would be installed to minimize the chances that a fire may cause an accidental release from the system. The refrigeration system would not require routine deliveries of anhydrous ammonia, but may require small quantities from time to time to keep the system charged. According to the Applicant, this occasional recharge would require only approximately 300 pounds of additional refrigerant every four to five years, delivered by tanker truck with varying degrees of load as part of routine deliveries to other recipients. Additionally, it may be necessary to drain and recharge the entire system during the life of the plant.

The worst-case accidental release in the AFC is associated with a failure at the location of the high-pressure receiver where all 5400 pounds of anhydrous ammonia could be emitted. According to the AFC, the nearest residence to the BEP II facility is approximately 0.75 miles southwest. The community of Mesa Verde is about 2.2 miles southwest of the anhydrous ammonia refrigerating system. About 5 to 6 isolated residences are also located on the elevated Palo Verde Mesa near the BEP II site. According to the modeling results for worst-case scenario, the nearest residence may experience ammonia concentrations slightly over 400 ppm while the surrounding population could be impacted by concentrations greater than 100 ppm. (FSA, p. 4.4-7 & 8)

To assess the potential impacts associated with an accidental release of either anhydrous or aqueous ammonia, Energy Commission staff typically evaluates four off-site "bench mark" exposure levels of ammonia gas. These include:

1. the lowest concentration posing a risk of lethality, 2,000 ppm;
2. the Immediately Dangerous to Life and Health (IDLH) level of 300 ppm;
3. the Emergency Response Planning Guideline Level 2 (ERPG-2) of 150 ppm, which is also the RMP Level 1 criterion used by EPA and California; and
4. the level considered by the Energy Commission staff to be without serious adverse effects on the public for a one-time exposure: 75 ppm.

Since members of the off-site public would be exposed to airborne concentrations considerably in excess of Staff's 75 ppm, and some off-site public would even experience airborne concentrations in excess of the ERPG-2 and the IDLH level, staff found it necessary to conduct further review and evaluation of this option for the inlet chiller. To do this, Staff reviewed the accident frequency for releases from ammonia refrigeration units. This review also included an assessment which Staff conducted for the BEP I facility as found in the Final Staff Assessment for that project. For that project, Staff had requested that the Applicant provide an analysis of the potential for a release of anhydrous ammonia from the refrigeration unit. The Applicant provided results that indicated a probability of accidental release ranging between 7.2 in 10,000 and 3.6 in 100,000 plant years of operation. Further evaluation by Staff indicated that historically serious releases involving refrigeration plants occur at a frequency of about 1 in 100,000 per plant year of operation and that more recently, both serious and non-serious accidental releases from ammonia refrigeration systems have occurred at an even greater frequency in certain parts of the country.

Staff also evaluated the potential for impacts on three specific receptor locations including Mesa Verde, the Blythe Airport and on Interstate 10. The modeling results indicate that significant impacts would occur at Mesa Verde, about 2 miles from the project, with winds from the east and north east direction. Staff's analysis indicates that winds in the direction of Mesa Verde occur with a frequency of about 0.021 (about two percent of the time). Thus, significant impacts on Mesa Verde would have a probability of occurrence of about 2 in 10,000,000 per year. Staff's analysis of the Blythe Airport, about 1.5 miles from the project, indicates the probability of impact with winds from the southeast. These meteorological conditions occur with a frequency of about 0.011 (about one percent of the time). Thus, the risk of significant impact at the Blythe Airport is about 1 in 10,000,000. The modeling results indicate that impacts on Interstate 10, about 0.25 miles from the project, could be about 2 in 1,000,000. In general, Staff considers a risk above 1 in 1,000,000 per year significant with the potential of more than 100 serious injuries and or fatalities. Staff could not quantify the potential number of injuries or fatalities that could result from a release affecting Interstate 10. However, Staff does believe that such an event has the potential to cause more than 100 injuries and or fatalities on Interstate 10. While this level of risk cannot be considered insignificant, it is close to an insignificant level of risk. It is typical regulatory practice in such cases to impose mitigation to reduce risk to the lowest level that is reasonably practical.

After review of the accident release data and frequency of occurrence at ammonia refrigeration units, Staff has concluded that the accident release frequency and the resultant impacts can be significant. Indeed, the U.S. EPA issued a Safety Alert on Ammonia Used as a Refrigerant in 1998 and published a Chemical Safety Alert on ammonia releases from refrigeration facilities in 2001. This document also recommends the adoption and implementation of a hazard reduction plan at facilities that use anhydrous ammonia for refrigeration. Staff also investigated the leak of anhydrous ammonia at the BEP I power plant in September 2004. Staff found that the scrubber on the containment building did work but that due to a lack of monitoring capability, power plant personnel were unaware of the efficiency of the scrubber and therefore properly implemented the Emergency Response Plan. Staff has made several recommendations regarding preventing this type of accidental release and resulting disruption of traffic on I-10 from occurring again and will reiterate those recommendations for the BEP II. (FSA, p. 4.4-9) See Conditions **HAZ-8** and **HAZ-11**.

Staff also investigated the use of alternative chemicals for use as inlet chillers. One promising alternative currently in use in the United States and Europe is an aqueous lithium bromide absorption chiller. An aqueous solution of lithium bromide is much less toxic, and an accidental release would not result in off-site consequences. The Commission is asking the Applicant to seriously consider this alternative method, but is aware that the manufacturer of the combustion turbine may not provide a product warranty if a different chiller system is used. Thus, this alternative is not required. (FSA, p. 4.4-9)

Although the chances of accidental release from the proposed BEP II would be small, the impacts of such a release could be significant. Therefore, in order to reduce this risk to a level of insignificance, Condition **HAZ-8** requires the Applicant to prepare and implement an Ammonia Refrigeration Hazard Reduction Plan consistent with U.S. EPA guidelines. Additionally, technical organizations such as the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE), the International Institute of Ammonia Refrigeration (IIAR), and the American National Standards Institute (ANSI), have established codes, standards, and guidelines for the safe use of anhydrous ammonia as a refrigerant. The proposed refrigeration plant will also be subject to regulations requiring participation in the State Risk Management Program (RMP) and Process Safety Management (PSM) program post certification.

Participation in these programs will result in development and implementation of extensive administrative controls designed to improve the safety of the plant. Additionally, the record of past releases from refrigeration plants that suggests a significant causal relationship between fires and accidental releases from such plants supports the use of an automatic fire suppression system. Condition **HAZ-10** requires installation of an automatic fire suppression system on the refrigeration plant. Additionally, Condition **HAZ-11** requires certain ammonia monitors and automatic door closures be installed in the anhydrous ammonia containment building and vent scrubber.

With the implementation of these Conditions, the risks associated with the proposed use of anhydrous ammonia as refrigerant are below significant levels. (FSA, p. 4.4-10)

MITIGATION:

- ☑ The Project Owner shall implement a Hazardous Materials Management Plan and Risk Management Plan. Condition **HAZ-1**.
- ☑ The Project Owner shall implement an Ammonia Refrigeration Hazard Reduction Plan consistent with U.S. EPA guidelines. Condition **HAZ-8**.
- ☑ The Project Owner shall install an automatic fire suppression system and door closures in the ammonia refrigeration plant. Condition **HAZ-10**.
- ☑ The Project Owner shall install remotely readable sensors in the anhydrous ammonia containment building. Condition **HAZ-11**.

<u>Aqueous Ammonia</u>

The project will use Selective Catalytic Reduction (SCR) to reduce combustion-generated nitrogen oxide (NOx) emissions to comply with air permit requirements. The accidental release of aqueous ammonia without proper mitigation can result in very high down-wind concentrations of ammonia gas. Two storage tanks will be used to store the 19 to 30 percent aqueous ammonia with a maximum capacity of 10,000 gallons each.

The use of aqueous ammonia can result in the formation and release of toxic gases in the event of a spill even without interaction with other chemicals. This is a result of its moderate vapor pressure and the large amounts of aqueous ammonia that will be used and stored on-site. However, the use of aqueous ammonia instead of the much more hazardous anhydrous ammonia (i.e. ammonia that is not diluted with water) poses far less risk.

To assess the potential impacts associated with an accidental release of aqueous ammonia, Staff used the four “bench mark” exposure levels of ammonia gas described above for anhydrous ammonia. According to the Applicant, the worst-case release is associated with a failure of one of the storage tanks in the containment area, and the second scenario is associated with a spill from a delivery tanker truck during loading operation.

The results of the Applicant’s modeling showed that off-site airborne concentrations of ammonia would exceed the level staff uses to establish insignificance (75 ppm) out to a distance of 0.86 miles from the ammonia storage tank for the tank spill scenario modeled. The maximum concentration at the nearest site boundary (Hobsonway- approximately 0.15 miles or 800 feet south from the tank according to the AFC) was calculated to be approximately 2,000 ppm.

For the second scenario involving a spill from a delivery truck, the modeling showed a concentration of 75 ppm at 1.7 miles, and over 2,000 ppm at the nearest site boundary. ALOHA program used to model concentrations would significantly over-predict the threat zone of an aqueous ammonia release since it assumes that the entire content of an aqueous ammonia release is anhydrous ammonia (i.e., no water).

Staff has reviewed this Off-site Consequence Analysis and found the results to be indicative of significant off-site impacts. Since the applicant used an air dispersion model that significantly over-predicts downwind airborne concentrations, Staff conducted SCREEN 3 modeling for two different scenarios associated with a failure of the aqueous ammonia storage tank. The results of staff's modeling show that, if an accidental release of aqueous ammonia from the storage tank occurs, airborne concentrations of ammonia are predicted to be 2,558 ppm at the fence line and 170 ppm at the nearest residence for the worst-case spill. For the other more likely meteorological scenario, the airborne concentrations of ammonia are predicted to be 447 ppm at the fence line and 26 ppm at the nearest residence. Staff's modeling also found that for a transfer spill, the airborne concentration of ammonia is predicted to be 1,565 at the fence line and 105 ppm at the nearest residence for the worst-case spill and 275 ppm at the fence line and 16 ppm at the nearest residence. The predicted levels of 26 ppm and 16 ppm at the nearest residence for the more likely meteorological scenario do not represent a significant risk to the public.

Therefore, given the results of Staff's offsite consequence analysis, the finding that worst-case meteorological conditions are unlikely to occur with any significant frequency, the finding that the sparsely populated area would be very easy to evacuate should a release of aqueous ammonia occur, the use, storage and handling of aqueous ammonia will not cause a significant impact. (FSA, p. 4.4-12)

Although only a very small amount of anhydrous ammonia would be used at BEP II to recharge the system (~300 pounds) every 4 - 5 years, the tanker truck transporting the ammonia to BEP II would be just one of several deliveries to other locations and thus the tanker truck could contain varying amounts of anhydrous ammonia up to the tanker volume of 30,000 pounds.

MITIGATION:

- ☑ The Project Owner shall not store or use amounts of acutely hazardous materials in excess of listed quantities. Condition **HAZ-1**.
- ☑ A secondary containment basin shall protect the aqueous ammonia storage tank. Condition **HAZ-4**.
- ☑ The Project Owner shall direct all vendors delivering aqueous ammonia to use tanker trucks meeting or exceeding federal Department of Transportation anti-spill regulations. Condition **HAZ-6**.

<u>Hydrochloric Acid</u>

Hydrochloric acid (HCl) may be used initially for cleaning of the HRSGs, and then once every 3-5 years (unless an EDTA-based system is used). To assess the potential impacts associated with an accidental release, Staff uses three "bench mark" exposure levels of hydrogen chloride gas. These include:

1. The IDLH level of 50 ppm.
2. The public Emergency Exposure Guidance Level (EEGL) of 20 ppm, developed by the National Research Council for short-term public exposures, and is protective against severe effects.
3. The Cal-EPA 1-hour acute Reference Exposure Level (acute REL) of 1.4 ppm developed by the Office of Environmental Health Hazard Assessment to protect against mild irritative effects on the respiratory system.

Staff considers the NRC EEGL of 20 ppm to be the most useful benchmark in determining the potential for significant risk. Staff reviewed the Applicant's ALOHA modeling of an accidental release of hydrochloric acid and determined that all off-site airborne levels predicted by the Applicant's modeling under both meteorological scenarios are considerably in excess of all three bench mark levels used by Staff to assess impacts to public health.

However, Staff conducted its own modeling using the U.S. EPA SCREEN3 air dispersion model. Staff has traditionally used SCREEN3 to predict the worst-case ground level concentrations and impacts due to hazardous materials releases. Although SCREEN3 tends to over-estimate these levels, it does so to a lesser degree than the ALOHA model which has difficulty assessing the emissions of gases from an aqueous solution.

Staff assumed that 30% HCl in water would be used (this is consistent with other power plant projects) and that an accidental spill would result in a pool with a surface area of 3,283 square feet. (The spill was assumed to be limited to a reasonable size by taking into consideration an assumed location of the temporary HCl storage tank on-site, the slope of the area towards drains or berms, and immediate containment efforts.) Staff found that the airborne concentration predicted to occur at the fence line would be 1,065 ppm and 81 ppm at the nearest residence. This compares to the Applicant's modeling which predicts 2,000 ppm at the fence line and approximately 500 ppm at the nearest residence.

The airborne concentrations predicted by Staff's SCREEN3 modeling for the worst-case meteorological conditions are in excess of the EEGL of 20 ppm. Staff also found that for more likely meteorological conditions, the predicted airborne concentration of HCl at the nearest residence (12 ppm) would be below the EEGL.

Furthermore, Staff determined that because HCl would be used only temporarily, infrequently, and not stored on-site continuously, the risk of an accident resulting in a spill during worst-case meteorological conditions to be a very remote and insignificant probability.

Nevertheless, the airborne concentrations both on and off-site are significant and must be mitigated. Therefore, Condition **HAZ-9** would require the use of temporary containment berm(s) to limit the size of a spill of any HCl used to clean the HRSG to no more than 500 square feet, a spill size that dispersion modeling predicts would result in airborne concentrations of HCl below the EEGL of 12 ppm at the nearest residence under adverse meteorological scenarios. This would apply only to the undiluted acid and not the diluted HCl after adding to the water within the HRSGs and water/steam system piping. With Condition **HAZ-9** and the engineering controls proposed by the Applicant for the storage and transfer of hydrochloric acid, any accidental release of hydrochloric acid used for the project will not cause a significant impact. (FSA, p. 4.4-13 & 14)

MITIGATION:

- ☑ The Project Owner shall implement a Hazardous Materials Management Plan and Risk Management Plan. Condition **HAZ-1**.
- ☑ When cleaning the HRSG, a temporary containment berm shall be used to contain any spill of Hydrochloric acid (HCl). Condition **HAZ-9**.

<u>Other Materials</u>

During operations, acutely hazardous chemicals, such as cyclohexylamine, morpholine, ethanolamine, and methoxypropylamine, would be used and stored in relatively small amounts and represent limited off-site hazard due to their small quantities, low volatility, and/or low toxicity.

Sodium hypochlorite, sodium hydroxide, and sulfuric acid will be stored on-site but do not pose a risk of off-site impacts because they have relatively low vapor pressures, and thus spills would be confined to the site. Due to concern at another proposed energy facility in 1995, Staff conducted a quantitative assessment of the potential for impact associated with the transportation, storage and use of sulfuric acid. Staff found no hazard would be posed to the public due to the extremely low volatility of this aqueous solution of sulfuric acid. However, in order to protect against risk of fire, Condition **HAZ-5** requires that no combustible or flammable material is stored within 50 feet of the sulfuric acid tank. (FSA, p. 4.4-6)

Other hazardous materials stored in smaller quantities, such as mineral and lubricating oils, corrosion inhibitors, water conditioners and hydrogen are already present and are properly stored at the site. These materials pose no significant potential for off-site impacts as a result of the quantities on-site, their relative toxicity, and/or their environmental mobility. (AFC p. 5.15-4, 13.)

MITIGATION:

- ☑ No flammable material will be stored within fifty (50) feet of the sulfuric acid tank. Condition **HAZ-5**

<u>Natural Gas</u>

Natural gas poses some risk of both fire and explosion. Although no natural gas is stored on-site, the project will use natural gas in its operation. While natural gas will be used in significant quantities, it will not be stored on-site except for that amount contained within the delivery pipeline. No changes are needed to the existing piping network for the project. The risk of a fire and/or explosion from natural gas can be reduced to insignificant levels through adherence to applicable codes and the development and implementation of effective safety management practices. (FSA, p. 4.4-15.)

Disposal

Hazardous waste generated by the power plant will be minimal. Hazardous wastes will be collected by a licensed hazardous waste hauler and disposed of at a hazardous waste facility. (FSA, p. 4.13-4 & 5). (See also **WASTE MANAGEMENT**)

Cumulative Impacts

Staff reviewed the potential for the operation of the BEP II combined with existing facilities to result in cumulative impacts on the population within the area. The facility that has the most potential to contribute to cumulative impacts is the existing BEP I facility located adjacent to the proposed project site with about 1,600 feet separating the proposed BEP II ammonia storage area from the existing BEP I ammonia storage area. In the event of an accidental release of ammonia from both facilities at the same time, cumulative impacts would represent a higher concentration of ammonia in areas where the cloud of gas would overlap and an increase in the impacted zone. However, Staff believes that it is unlikely that an accidental release that has very low probability of occurrence (about one in one million per year) would independently occur at the BEP II site and BEP I at the same time. However, the Fire Service Needs Assessment pointed out the need for additional HazMat response equipment, training, and personnel. Staff agrees with this needs assessment. Staff also finds that the facility, as proposed by the Applicant and with the additional mitigation measures, poses a minimal risk of accidental release that could result in off-site impacts. Therefore, the proposed project would not contribute to a significant cumulative impact. (FSA, p. 4.4-17-18)

Findings

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to hazardous materials management and all potential adverse impacts related to hazardous materials management will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

HAZ-1 The project owner shall not use any hazardous material not listed below, or in quanities greater than those identified by chemical name below, unless approved in advance by the CPM.

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Trade Name	Chemical Name	Max. Quantity On-site	Trade Name	Chemical Name	Max. Quantity On-site
Aqueous Ammonia (19 to 30% solution)	Ammonium Hydroxide	20,000 gallons or 120,000 pounds	Hydroxy Acetic Acid	Gyrolic Acid	1,000 pounds
NALCO 356 or Equivalent	Cyclohexylamine (20 - 40%) Morpholine (5 – 10%)	2,000 gallons	Formic Acid	Methanoic Acid	600 pounds
TRIACT 1800 or Equivalent	Ethanolamine (10 - 20%) Methoxyropylamine (10 – 20%) Cyclohexylamine (10 – 20%)	2,000 gallons	STABREX ST70 or Equivalent	Sodium Hydroxide (1 – 5%) Sodium Hyprobromite (10 – 20 %)	2,000 gallons
Sulfuric Acid	Sulfuric Acid	6,000 and 2,000 gallons	NALCO 7280 or Equivalent	Polyacrylic Acid (20 – 40%)	250 gallons
Aluminum Sulfate	Aluminum Sulfate	??	ELIMIN-OX or Equivalent	Carbohydra-zide	2,000 gallons
Bleach	Sodium Hypochlorate	6,000 gallons	NALCO 7408 or Equivalent	Sodium Bisulfite (40 – 70%)	250 gallons
Sodium Hydroxide	Sodium Hydroxide	6,000 gallons	NALCO 22106 NALCO 7213 or Equivalent	Sodium Plyacrylate Aryl Sulfonate Tetrasodium ethylenedia minetetraace-tate (10 – 20%)	2,000 gallons
Disodium Phosphate	Sodium Phosphate	500 pounds	Mineral Insulating Oil	Oil	25,000 to 40,000 gallons
Trisodium Phosphate	Tri-sodium Phosphate	500 pounds	Lubrication Oil	Oil	12,000 gallons
Ammonium Biflouride	Ammonium Biflouride	500 pounds	Hydraulic Oil	Oil	600 gallons
Sodium Carbonate	Sodium Carbonate	500 pounds	Various Detergents	Various	100 gallons
Hydrochloric Acid	Hydrochloric Acid	10,000 gallons	Laboratory Reagents	Various	Small Quantities
Citric Acid or Equivalent	Hydroxy-propoinic-tricarboxylic acid	500 pounds	Laboratory Reagents (Solids)	Various	Small Quantities

Verification: The project owner shall provide to the Compliance Project Manager (CPM), in the Annual Compliance Report, a list of those hazardous materials contained at the facility.

HAZ-2 The project owner shall concurrently provide a Business Plan (including a Hazardous Materials Management Plan) and a Risk Management Plan (RMP) to the Certified Unified Program Authority – (CUPA) (Riverside County Hazardous Materials Division) and the CPM for review at the time the RMP is first submitted to the U.S. Environmental Protection Agency (EPA). After receiving comments from the CUPA, the EPA, and the CPM, the project owner shall reflect all recommendations in the final documents. Copies of the final Business Plan and RMP shall then be provided to the CUPA and EPA for information and to the CPM for approval.

Verification: At least 60 days prior to receiving any hazardous material on the site to support plant commissioning and operations, the project owner shall provide a copy of a final Business Plan to the CPM for approval. At least sixty (60) days prior to delivery of aqueous ammonia to the site, the project owner shall provide the final RMP to the CUPA for information and to the CPM for approval.

HAZ-3 The project owner shall develop and implement a Safety Management Plan for delivery of aqueous ammonia. 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 aqueous ammonia with incompatible hazardous materials.
Verification: At least sixty (60) days prior to the delivery of aqueous ammonia to the facility, the project owner shall provide a safety management plan as described above to the CPM for review and approval.

HAZ-4 The aqueous ammonia storage facility shall be designed to either the ASME Pressure Vessel Code and ANSI K61.6 or to API 620. In either case, the storage tank shall be protected by a secondary containment basin capable of holding 125% of the storage volume or the storage volume plus the volume associated with 24 hours of rain assuming the 25-year storm. The final design drawings and specifications for the ammonia storage tank and secondary containment basins shall be submitted to the CPM.

Verification: At least sixty (60) days prior to delivery of aqueous ammonia to the facility, the project owner shall submit final design drawings and specifications for the ammonia storage tank and secondary containment basin to the CPM for review and approval.

HAZ-5 The project owner shall ensure that no flammable material is stored within 50 feet of the sulfuric acid tank.

Verification: At least sixty (60) days prior to receipt of sulfuric acid on-site, the Project Owner shall provide copies of the facility design drawings showing the location of the sulfuric acid storage tank and the location of any tanks, drums, or piping containing any flammable materials

HAZ-6 The project owner shall direct all vendors delivering aqueous ammonia to the site to use only tanker truck transport vehicles which meet or exceed the specifications of DOT Code MC-307 and that all vendors delivering anhydrous ammonia to the site use only tanker truck transport vehicles that meet or exceed the specifications of DOT Code MC-330 or 331.

Verification: At least sixty (60) days prior to receipt of aqueous ammonia on site, the project owner shall submit copies of the notification letter to supply vendors indicating the transport vehicle specifications to the CPM for review and approval.

HAZ-7 The project owner shall direct all vendors delivering any hazardous material to the site to use only the route approved by the CPM (I-10 to Neighbors Boulevard. to Hobsonway to Buck Boulevard). The project owner shall obtain approval of the CPM if an alternate route is desired.

<u>Verification:</u> At least sixty (60) days prior to receipt of any hazardous materials on site, the project owner shall submit copies of the required transportation route limitation direction to the CPM for review and approval.

HAZ-8 The project owner shall develop and implement an Ammonia Refrigeration Hazard Reduction Plan. This plan shall include procedures, protective equipment requirements, training and a checklist, as described in the August 2001 EPA Chemical Safety Alert. It shall also include a section describing all measures to be implemented to prevent the leaking of anhydrous ammonia from the refrigeration system. This plan shall also incorporate recommended practices as found in ANSI Standards 15-2001 and 34-2001 and the ASHRAE Position Document on Ammonia As A Refrigerant (January 17, 2002). The project owner shall also include appropriate elements of the Cal-OSHA Process Safety Management standard (8 CCR section 5189).

<u>Verification:</u> At least sixty (60) days prior to the delivery of anhydrous ammonia to the facility, the project owner shall provide a safety management plan as described above to the CPM for review and approval.

HAZ-9 When cleaning the HRSG, the project owner shall provide or contract to provide temporary berm(s) to contain any spill of HCl to no more than 500 square feet.

<u>Verification:</u> At least sixty (60) days prior to delivery of the initial HRSG cleaning chemicals to the site, the project owner shall submit final design drawings and specifications for the temporary surface containment berm(s) to the CPM for review and approval.

HAZ-10 The project owner shall install an approved automatic fire suppression system in the ammonia refrigeration plant.

<u>Verification:</u> At least sixty (60) days prior to delivery of anhydrous ammonia to the facility, the project owner shall provide final design drawings and specification for the fire protection system approved by a registered Safety Engineer to the CPM for review and approval.

HAZ-11 The project owner shall install an ammonia sensor on the discharge from the scrubber on the anhydrous ammonia refrigeration unit containment building that can be remotely read in the power plant control room and remotely read by a laptop computer operated by power plant personnel, the Blythe Fire Department and the Riverside County Fire Department. This sensor and all other sensors located inside the containment building shall be able to detect ammonia concentrations within a range of at least 10 to 20,000 ppm and shall be reported to the power plant control room on a real-time recordable basis. Additionally, the project owner shall:

1. Perform a process safety evaluation of hazards associated with the chilling system and provide anhydrous ammonia release prevention features for the chilling system

equipment and containment structure to enhance the safety of operators and emergency response personnel;

2. Require that any routine maintenance or repair work on the anhydrous ammonia refrigeration unit is conducted only during normal daytime work hours;

3. Require that maintenance or repair on any filter train be conducted only under lockout/tagout safety procedures;

4. Provide handheld ammonia vapor detectors and direct that they be used by workers whenever entering the ammonia refrigeration unit containment building; and

5. Conduct joint training and exercises at least annually with the Blythe Fire Department, the Riverside County Fire Department, the Riverside County Hazardous Materials Response Team, the Blythe Police Department, and site staff.

Verification: At least sixty (60) days prior to delivery of anhydrous ammonia to the facility, the project owner shall provide the final design drawings and specification for the above systems, the results and recommendations of the process safety evaluation of hazards associated with the chilling system, and an agreement with the Blythe Fire Department, the Riverside County Fire Department, the Riverside County Hazardous Materials Response Team, and the Blythe Police Department to conduct joint training and exercises with site personnel at least annually to the CPM for review and approval.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

HAZARDOUS MATERIALS

APPLICABLE LAW	DESCRIPTION
FEDERAL	
Clean Air Act (40 CFR 68)	Requires a RMP if listed hazardous materials are stored above threshold quantities (TQ).
Clean Water Act (40 CFR 112)	Requires preparation of an SPCC plan if oil is stored above TQ.
SARA Title III, Section 302	Requires certain planning activities when EHSs are present in excess of TQ. Aqueous ammonia to be used onsite in excess of TQ.
SARA Title III, Section 311	MSDSs to be kept onsite for each hazardous material. Required to be submitted to SERC, LEPC and local fire department.
SARA Title III, Section 313	Requires annual reporting of releases of hazardous materials.
49 CFR 171-177	Governs the transportation of hazardous materials, including the marking of the transportation vehicles.
STATE	
Health & Safety Code §25500, et seq. (Waters Bill)	Requires preparation of HMBP if hazardous materials are handled or stored in excess of threshold quantities.
Health & Safety Code §25531, et seq.	Requires registration of facility with local authorities and preparation of RMP if hazardous materials stored or handled in excess of threshold quantities.
CCR Title 8, Section 5189	Facility owners are required to implement safety management plans to ensure safe handling of hazardous materials.
California Building Standards Code	Requirements regarding the storage and handling of hazardous materials.
California Government Code, Section 65850.2	Restricts issuance of COD until facility has submitted a RMP.

LAND USE – Summary of Findings and Conditions

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
General/Special Plans	**CONDITION**	**None**	**YES**

The General Plan designates the BEP II site as Heavy Industrial (I-H). The proposed project is generally compatible with land uses immediately adjacent to the site, which consist of an orchard on the east side and vacant land on the remaining areas. The General Industrial Zone allows a variety of manufacturing uses including utility operations facilities; however, this zone does contain a maximum height restriction of thirty-four (34) feet. The City Planning Department approved a height variance request for three 125-foot transmission towers, two 130-foot high exhaust stacks, and one 99-foot high brine concentrator. The multiple site parcels are to be consolidated into one parcel.

The City of Blythe overruled the Riverside County Airport Land Use Commission's determination that the project is inconsistent with the Airport's Comprehensive Land Use Plan, by determining the project is consistent with public health, safety, and welfare with the imposition of conditions related to flight safety.

CONDITION:

- ☑ The project owner shall prepare a site development plan that complies with applicable design criteria and performance standards of the General Plan. Condition: **LAND-1**.
- ☑ The project owner shall provide descriptions of the final construction laydown and staging areas. Condition: **LAND-2**.
- ☑ The project owner shall comply with the Airport Land Use Commission's condition requiring conveyance of an avigation easement. Condition: **LAND-4**.
- ☑ The project owner shall consolidate multiple parcels containing all project facilities, except linear facilities. Condition: **LAND-5**.

Existing/ Planned Uses	CONDITION	None	YES
	The project's presence in the Blythe Airport's 'zone of approach" is consistent with the FAA's regulations on structural obstructions. Implementation of an *advisory* "No Fly Zone" preferably over the power plant complex (for security reasons), but at a minimum, over the cooling towers for flight safety reasons assure that the project does not impede safe access to the Blythe Airport. (See **TRANS-9**) The proposed project would be compatible with nearby agricultural uses. If the Water Conservation Offset Program permanently retires land from irrigated production, the land would not be permanently converted to non-agricultural uses under this option, which will be mitigated by securing the acquisition of agricultural easements and/or paying a fee to an agricultural land trust. **MITIGATION:** ☑ If the WCOP causes the permanent retirement of irrigated farmland, the Project Owner shall mitigate at a one-to-one acre ratio conversion of productive farmland by payment of a mitigation fee or acquisition of an agricultural easement. Condition: **LAND-3**.		

LAND USE - GENERAL

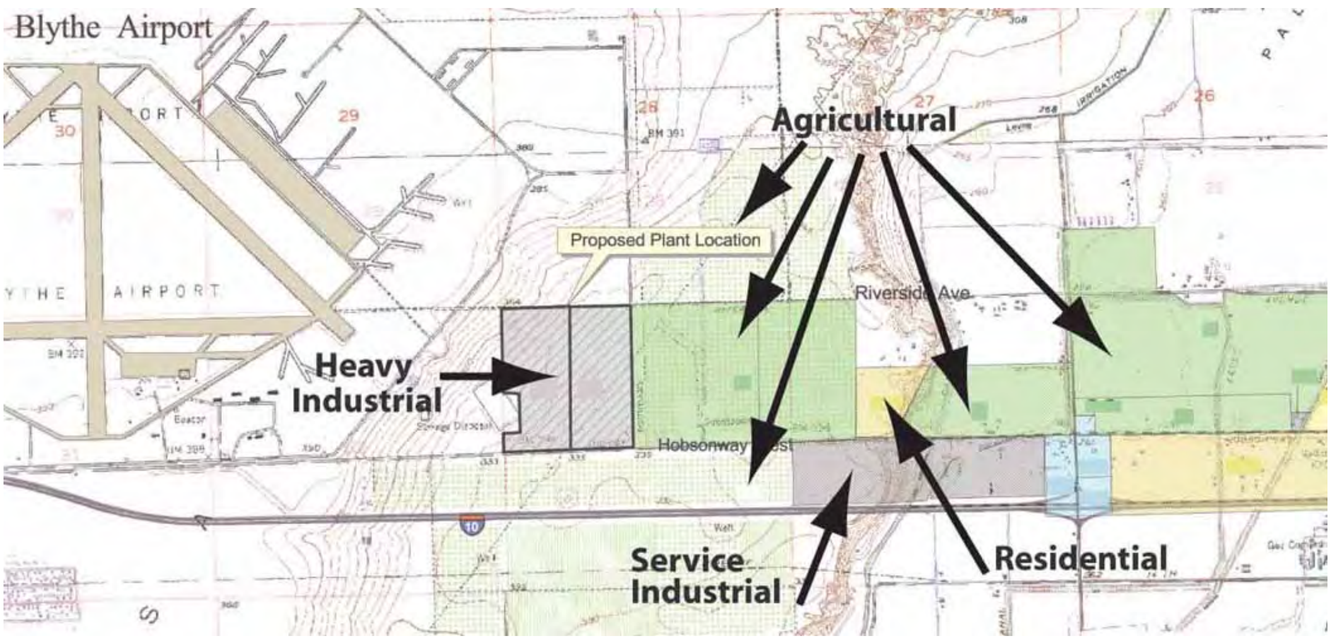
Land uses are controlled and regulated by a system of plans, policies, goals, and ordinances that are adopted by the various jurisdictions with land use authority over the area encompassed by the proposed project.

The BEP II site is located about 5 miles west of downtown Blythe in eastern Riverside County, in a recently annexed portion of the City of Blythe and about one mile east of the Blythe Airport. The site is located approximately 1,000 feet north of Interstate 10 (I-10), a major regional transportation corridor extending east-west through the area.

The BEP II power plant site is located within a 1,253-acre area recently annexed to the City, which extends from the City's previous western boundary to the eastern boundary of the Blythe Airport property. The annexation became final on November 28, 2000. The BEP II site is located in an area called Mesa Verde (the Mesa), above the Palo Verde Valley, which is an intensive agricultural region. Commodities grown in the area include citrus, melon, vegetable, and field crops such as alfalfa. Nearly all of the cultivated areas are irrigated with water from the Colorado River aquifer, supplied from the Palo Verde Irrigation District or from domestic wells. The site is classified as Farmland of Local Importance. Similar soil types occur on the irrigated lands immediately adjacent, to the east of the site, which are designated Prime Farmlands, and contain a declining lemon grove.

BEP II would be built on the 76-acre expansion portion of the original 76-acre Blythe Energy Project Phase I (BEP I) site, on the west side of the original site. The entire BEP I/BEP II 152-acre site is to the north of and adjacent to Hobsonway, a two-lane arterial road oriented East-West, and to the west and adjacent to Buck Boulevard. Hobsonway is a four-lane local arterial road that connects the Blythe Airport with the City of Blythe. The construction of BEP I has recently been completed on the original site, and the expansion site has been used for storage of approximately 200,000 cubic yards of excess soils from construction of the BEP I evaporation ponds and retention basin. This soil has been graded, compacted and stabilized on the BEP II site. (FSA, p. 4.5-5)

Land uses surrounding the site include the Blythe Airport facilities, large parcel agriculture, electric utilities, highways, and residential and industrial structures. An unincorporated residential community, within the Mesa Verde area, is located approximately 2 miles southwest.



Properties immediately adjacent and to the west, north and south (across Hobsonway) are undeveloped. The property to the immediate east is a declining lemon grove. The Western Area Power Administration (Western) owns the Blythe Substation. The Substation occupies a site approximately 12 acres in size, surrounded on three sides by the lemon grove. The Blythe Substation connects five existing 161-kV transmission lines serving the region.

Except for agriculture and some scattered residences and industrial uses, the properties within one mile of the power plant site are largely undeveloped. Highway-serving commercial uses are located on the north side of Interstate 10 (I-10) at the interchange south of the Blythe Airport.

Blythe is the only incorporated city within the Palo Verde Valley planning area. Unincorporated communities in the Palo Verde Valley Area include Mesa Verde, located approximately 2 miles southwest of the project site; and Ripley, located approximately 6 miles to the south of the City and the project site. The predominant land use in the area is irrigated agriculture and related enterprises. Other land uses include residential and recreational development mainly focused on the Colorado River, which borders the City of Blythe on the east. Commercial land uses serve the needs of agriculture, local residents, pass-through travelers, and recreational visitors. I-10 is a major interstate and regional transportation corridor, which extends east-west through the area.

Mesa Verde is the largest concentration of residential land uses in the proximity of the project. The major residential portion of the City of Blythe is located about five miles to the east. There are small numbers of farm and other residents near the site, mostly located south and east of the project site. The nearest residence is located 0.75 mile southwest of the power plant site.

The Blythe Airport is located approximately one mile west of the proposed BEP II power plant site. The Blythe Airport is the largest airport serving eastern Riverside County and serves primarily general aviation demand in the Blythe area. The Airport is classified in the National Plan of Integrated Airport Systems as a general aviation transport airport, designed to accommodate business jets, cargo type aircraft, light private planes, and flight school training activities. The Blythe Airport currently has two runways. The primary runway is Runway 8-26, which is oriented generally east-west. The BEP II power plant stacks would be located approximately 4,450 feet southeast of this runway, which is situated at an elevation of 393 feet mean sea level (MSL). The elevation of the BEP II site is about 335 feet MSL. Therefore, the 130-foot heat recovery stream generator (HRSG) stacks would be about 72 feet higher than the end of the runway. The project's on-site transmission pole-type towers are single circuited, and will be approximately 125 feet tall.

The Blythe Airport has been designated as a County redevelopment area. The intent is to encourage expansion of airport facilities and commercial and industrial development at the airport. The County's redevelopment plans are described in the Riverside County *Redevelopment Plan for Redevelopment Project Airports*, County of Riverside Economic Development Agency 1988. (FSA, p. 4.5-5-7)

According to the Guidelines to the California Environmental Quality Act (CEQA), a project may have a significant effect on land use and planning if a proposed project would:

- conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project adopted for the purpose of avoiding or mitigating an environmental effect;
- disrupt or divide the physical arrangement of an established community; or
- convert Prime Farmland, Farmland of Statewide Importance, or Unique Farmland to non-agricultural use.

A project may also have a significant impact on land use if it would create unmitigated noise, dust, public health hazard or nuisance, traffic, or visual impacts or when it precludes or unduly restricts existing or planned future uses. (FSA, p. 4.5-1)

General/Specific Plans

Subdivision Map Act

BEP II would be located entirely within the BEP I site's expanded boundaries. The site is comprised of four parcels. BEP I has been constructed on Parcels 34 and 35; a lot line adjustment was recorded with Parcel 34 to create a separate Parcel "B" for the Buck Boulevard Substation. BEP II would be located on the expansion portion of the site, parcels 36 and 37 and is not owned by the same entity as BEP I. The BEP II facilities would occupy approximately 10.45 acres of the property excluding the evaporation ponds and the cultural resources avoidance area, which consist of approximately 7.5 acres. Condition **LAND-5** would require a lot line adjustment creating one parcel accommodating or containing all project facilities, except for linear facilities. (FSA. p. 4.5-9)

CONDITION:

- ☑ The project owner shall consolidate multiple parcels containing all project facilities, except linear facilities. Condition: **LAND-5**.

City of Blythe General Plan/Zoning Ordinance

The City General Plan designates the BEP II site as Heavy Industrial (I-H). The project is consistent with this designation, and the City's goals for new additional industrial development.

The proposed project is generally compatible with land uses immediately adjacent to the site, which consist of an orchard on the east side and vacant land on the remaining areas. In general, the City's agricultural goals and policies encourage the continuation of agricultural use in the incorporated area. However, BEP II is potentially in conflict with these goals and policies if the proposed Water Conservation Offset Plan (WCOP) includes permanent retirement of irrigated land. In this case, the WCOP would reduce prime farmland acreage, and without mitigation, would be a significant impact. (FSA, p. 4.5-9)

The General Industrial Zone allows a variety of manufacturing uses including public maintenance services, utility operations facilities, custom manufacturing, general manufacturing, and warehousing. (City of Blythe Zoning Ordinance §17.08 010) The proposed power plant would be considered a Utility Operations Facility as defined in §17.08.710 and allowed in the Heavy Industrial zone. This zone, however, does contain a maximum height restriction of thirty-four (34) feet (§17.10.040). The heights of structures included in the design of the proposed power plant may exceed the zoning district height limitations. The Generation Building, Heat Recovery Steam Generator, Cooling Tower, Raw Water Supply, and Tank Demineralized Water Storage Tank may fall within the definitions included in City Zoning Ordinance Par. 17.10.041, "Commercial broadcast antennas, communications towers and microwave masts", and would be within the maximum height identified in this paragraph of 109 feet.

On March 8, 2004, the City of Blythe Planning Department approved a height variance request for three 125-foot transmission towers, two 130-foot high exhaust stacks, and one 99-foot high brine concentrator. In addition, the City's Project Review Committee (PRC) reviewed the project and recommended conditions of approval to the City for review and approval. On March 23, 2004, the City Council, by Minute Order approved the recommended conditions that were forwarded to the Applicant and the Energy Commission for inclusion in the Conditions of Certification for each responsible section.

No conditions were identified by the PRC for land use issues, although the project must comply with the applicable design criteria and performance standards for the General Industrial District set forth in the City of Blythe Zoning Ordinance. (FSA, pp. 4.5-9-10)

CONDITION:

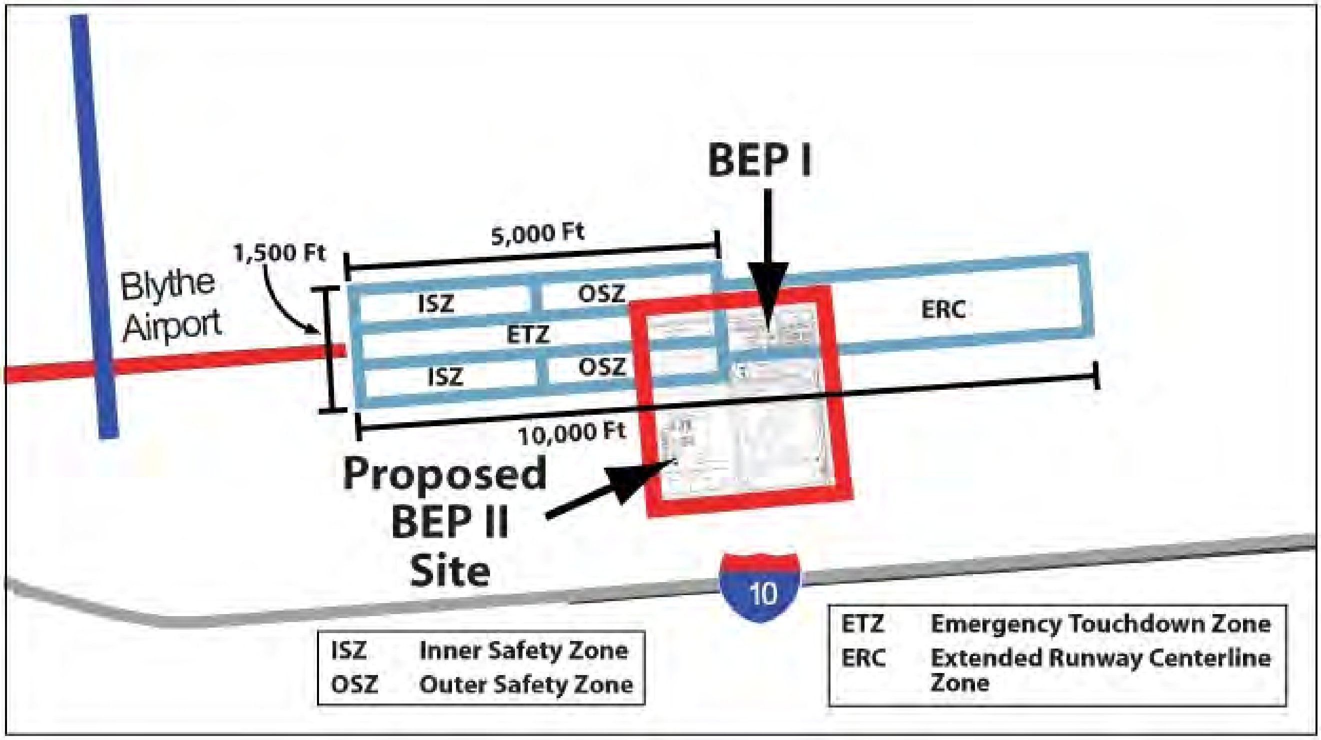
- ☑ The project owner shall prepare a site development plan that complies with applicable design criteria and performance standards of the General Plan. Condition: **LAND-1**.
- ☑ The project owner shall provide descriptions of the final construction laydown and staging areas. Condition: **LAND-2**.

Blythe Airport Comprehensive Land Use Plan

As described in the Riverside County-adopted Comprehensive Land Use Plan (CLUP), five safety zones are defined around airports to promote the safety of persons on the ground while reducing risks of serious harm to crews and passengers of aircraft making forced landings in the immediate environs of the airport. The CLUP provides land use compatibility guidelines that apply to each of these zones. The Traffic Pattern Zone (TPZ) extends approximately 10,000 in all directions surrounding the airport. The zones at the ends of the runways are:

- Inner Safety Zone (ISZ);
- Outer Safety Zone (OSZ;);
- Emergency Touchdown Zone (ETZ); and the
- Extended Runway Centerline (ERC).

As shown, the 152-acre power plant site is within three of these safety zones: the OSZ, the ETZ, and the ERC. The BEP II project structures are in the large TPZ, but not within any near-airport zone. The adjacent, existing BEP I structures also occupy about 10-acres, which are within the ERC and TPZ zones. (FSA, p. 4.5-11)



The CLUP states that any uses posing the following risks to aircraft in flight shall be prohibited within all safety zones, including light and reflection interference; smoke, or water vapor; gathering of birds; and electrical interference. The CLUP includes, from the State Airport Land Use Planning Handbook, detailed descriptions of these risks, including any use "which may otherwise affect safe air navigation within this area."

Regarding these risks, the CLUP states only a few kinds of land uses have inherent attributes that would make them necessarily violate these standards. (Landfills and power generating plants are examples.) The CLUP did not elaborate on the inherent attributes that cause power plants to trigger these risks and/or standard violations.

The Applicant states that all project features located in the safety zones are consistent with the CLUP. However, the July 18, 2002 report by the Riverside County Airport Land Use Commission (ALUC) made an advisory determination that the project would be inconsistent with the CLUP. The ALUC staff report for the project considered a number of issues related to land use in making its recommendation of inconsistency including the project's capacity to attract wildlife, the need for legal easements and project signs, lighting, sun reflection, smoke and water vapor generation, and electrical interference. The ALUC staff report noted the inherent incompatibility of power plants with the Blythe Airport if located in any of the safety zones, such as the BEP II's location within the airport's Traffic Pattern Zone (TPZ).

The Airport Land Use Commission staff report dated July 18, 2002, asserts that water vapor can attract large concentrations of birds, which may affect safe air navigation within the area. However, the ALUC staff report does not note as a safety issue the possibility of danger to air traffic from thermal plumes generated by the project. The ALUC has recommended mitigating conditions. However, ALUC staff has stated that even with the implementation of the conditions, the project would still be inconsistent with the CLUP. However, the ALUC staff report *does not* note as a safety issue the possibility of danger to air traffic from thermal plumes generated by the project. (FSA, 4.5-12)

On July 26, 2004, the City of Blythe, which has a contract with Riverside County to operate the Airport, unanimously approved Resolution No. 04-897 and overruled the negative advisory vote of the ALUC, as provided by Public Utilities Code section 21676, which requires findings that the City's action on the project is consistent with section 21670.

> It is the purpose of this article to protect public health, safety, and welfare by ensuring the orderly expansion of airports and the adoption of land use measures that minimize the public's exposure to excessive noise and safety hazards within areas around public airports to the extent that these areas are not already devoted to incompatible uses. (Pub. Util. Code, § 21670(a)(2)

The Energy Commission staff and Caltrans staff do not believe that the City of Blythe's findings support the overruling of the ALUC's determination and concurs with the ALUC that the project is inconsistent with the CLUP. The ALUC stated that, even if the mitigating land use condition in its report were implemented, the project would still be inconsistent with the CLUP, specifically the requirement that the storage or distribution of explosives or flammable materials is prohibited in the ERC zone. (FSA, p. 4.5-20)

Energy Commission staff believes that only the land use issues noted by the ALUC staff report could be adequately mitigated through a condition requiring conveyance of an avigation easement. However, *in Staff's view*, the issue of thermal plumes, which is not included in the ALUC's staff report, would fall under the CLUP's admonition against any use "… which may otherwise affect safe air navigation…." (FSA, pp. 4.5-19-20)

In addition to asserting that the City's findings are substantively insufficient to support overruling the ALCU's determination, the Staff states in its Opening and Reply Briefs that the City cannot "override" the inconsistency with the CLUP. Rather, the Energy Commission is the sole agency vested with the authority to override any determination of inconsistency. (See Public Resources Code section 25525.)

Commission Discussion

So long as Resolution 04-897 contains, on its face, findings that the project is consistent with the broad public health, safety and welfare purposes stated in Public Utilities Code section 21670, quoted above, the Commission will not second-guess the substantive adequacy of the findings. Moreover, the provisions of Public Resources Code section 21676 unequivocally provide a mechanism for a city to overrule the determinations of an ALUC regarding a CLUP. We note again that the ALUC staff, itself, *did not* include thermal plume issues in its determination. Rather, the Energy Commission staff has piggybacked its thermal plume issue onto the CLUP. Energy Commission staff suggests in its Reply Brief (p. 13) that the City Resolution must have included conditions which eliminate any inconsistencies in the ALUC determination. The express terms of Public Resources Code section 21676 do not require elimination of the inconsistencies, rather merely a finding that, in this case, the project is "consistent with the purposes" of section 21670, quoted in full above. Notwithstanding, the

City Resolution enumerated 12 conditions, one with 7 subparts, relating to the ALUC report or other legal requirements. In this case, the City has properly overruled the ALUC's inconsistency determination; as a result there is no residual inconsistency with an applicable law or regulation that would require a Commission override.

The Commission also notes that the CLUP prohibits creating water vapor in the airport environment. Interestingly, the ALUC staff report dated July 18, 2002, addresses water vapor in the context of attracting large concentrations of birds, which may affect safe air navigation within the airport area. The water vapor reference in the ALUC staff report is not to visible thermal plumes. As discussed in the **WATER QUALITY & SOILS** section of this Decision, the Applicant has substituted a Zero Liquid Discharge system for its large evaporation pond, which could have attracted birds in the absence of mitigation measures. The ALUC made its determination in 2002 based upon the use of the evaporation ponds. The thermal plume issues are discussed in the **TRAFFIC AND TRANSPORTATION** section of this Decision including that visible plumes inherently provide an avoidance warning to pilots and no evidence cites instances of visible plumes obscuring the runway. The Commission observes that in the BEP I licensing Decision (P800-01-010) the ALUC found that the BEP I project, which uses an evaporation pond, was consistent with the CLUP, with only the avigation easement condition. (Page 257)

CONDITION:

- ☑ The project owner shall comply with the Airport Land Use Commission's condition requiring conveyance of an avigation easement. Condition: **LAND-4**.

Existing/Planned Uses

The proposed power plant**,** located in a largely non-urbanized area, will not physically divide an established community.

Airport Uses

Public Utilities Code sections 21402 and 21403(c) prohibit any land use that would interfere with the right of flight in open (air) space. The right of flight includes the right of safe access to public airports including the right of flight within the zone of approach of any public airport without restriction or hazard. The Code sections provide:

> 21402. The ownership of the space above the land and waters of this State is vested in the several owners of the surface beneath, subject to the right of flight described in Section 21403. No use shall be made of such airspace which would interfere with such right of flight; provided, that any use of property in conformity with an original zone of approach of an airport shall not be rendered unlawful by reason of a change in such zone of approach.
>
> 21403(c) The right of flight in aircraft includes the right of safe access to public airports, which includes the right of flight within the zone of approach of any public airport without restriction or hazard. The zone of approach of an airport shall conform to the specifications of Part 77 of the Federal Aviation

Regulations of the Federal Aviation Administration, Department of Transportation.

BEP II is located in the zone of approach of the Blythe Airport. Staff believes BEP ll's cooling towers would emit non-visible thermal plumes that would cause moderate to severe turbulence during certain weather conditions. This turbulence could cause a pilot to lose control of the aircraft as it flies over the plant on approach or while executing a missed approach. Staff concludes that this interferes with the right of aircraft to fly into the Blythe airport and is inconsistent with the Public Utilities Code.

The "zone of approach" for the Blythe Airport does conform to Part 77 of the Federal Aviation Regulations. Title 14, Code of Federal Regulations, Section 77.1, *et. seq*. requires an applicant to notify the FAA of any construction or alteration of more than 200 feet above grade into navigable airspace. FAA obstruction criteria take into consideration primarily solid objects such as buildings and towers. BEP II filed applications with the FAA, and in response, FAA found that the proposed HRSG stack would not exceed obstruction standards and would not be a hazard to navigation. Based on this evaluation, the FAA determined that marking and lighting the HRSG stacks would not be necessary. However, in its Override Resolution, the City of Blythe recommended lighting improvements be added to the BEP ll stacks similar to those installed on BEP l and consistent with FAA Advisory Circular 70/7460-1K. (FSA, pp. 4.10-24-25)

Staff testified that the FAA is limited to evaluating the height of project structures and can only evaluate those structures that exceed the defined Part 77 surfaces. The FAA is not able to consider the impact of non-structural aspects of a project, such as thermal plumes, on aviation safety. As is stated in the Caltrans Handbook, and discussed in Staff's testimony, "tall objects in the approach corridors may pose risks even though they do not penetrate the defined Part 77 surfaces." (FSA, 4.10-25)

The Commission thoroughly discusses flight safety as it relates to the project's thermal plumes in the **TRAFFIC & TRANSPORTATION** section of this Decision. The Commission is appropriately concerned about flight risks to student and experienced pilots due to the project's thermal plume turbulence. As a Condition of Certification, subject to FAA approval, the Commission has adopted agreed-upon measures to provide broadcast notification to pilot and change landing procedures. (See **TRANS-9**) The flight safety measures in the Condition of Certification assure that the project does not impede safe access to the Blythe Airport, and thus the project conforms to Public Resources Code sections 21402 and 21403(c).

<u>Other Uses</u>

The proposed project would be compatible with nearby agricultural uses. The proposed project would not adversely affect agricultural practices and would not restrict normal operations of citrus orchards in the area. With the implementation of the Conditions of Certification contained in the **AIR QUALITY** section that require control of fugitive dust, the project's construction activities would not adversely affect agricultural crops in the area.

The BEP II site is classified as Farmland of Local Importance. The Farmland of Local Importance designation is applied where soil types would qualify as prime farmland if the land were irrigated. (FSA, p. 4.5-13-14)

WCOP Farmland Impacts

The Applicant proposes to implement a voluntary Water Conservation Offset Program (WCOP) by which it will fallow or retire irrigated farmlands in an amount equivalent to the amount of groundwater it will extract for project cooling. While the WCOP's 786 acres of irrigated agricultural lands represent only 0.7 percent of the total irrigated lands in the Palo Verde Valley agricultural district, loss of agricultural land is a regional and statewide concern. Loss of agricultural production is an incremental process, which eventually has an effect on the ability of a region to sustain agriculture and the agriculturally related service economy.

The WCOP proposes to retire irrigated lands permanently or fallow lands on a rotating basis to reduce demand for agricultural irrigation. Acquisition of lands and/or irrigation rights would be accomplished through purchase or lease by BEP II. The WCOP would include the permanent retirement or rotational fallowing of lands within Palo Verde Irrigation District (PVID) boundaries on the Mesa or the Palo Verde Valley. If the land retirement option is chosen, the Applicant has stated that the land to be retired would not result in a Williamson Act contract violation. This option would result in the permanent loss of prime farmland, which would be a significant impact. An estimated total of up to 786 acres would be retired based on an assumed consumptive water use rate of 4.2 acre-feet per acre.

If the WCOP utilizes full or partial rotational fallowing, the amount of land in the WCOP could be greater in order to allow for the necessary transition of acreage at any one time. . On a general basis, there would not be a significant impact if the rotational land fallowing option were chosen.

However, if the Applicant proceeds with the WCOP option of permanently retiring land from irrigated production, the land would not be permanently converted to non-agricultural uses under this option. The Applicant can mitigate the loss of prime agricultural land by means of a mitigation fee to the City of Blythe or Riverside County agricultural land trust or securing the acquisition of agricultural easements

Much of the lands on the Mesa that are in agricultural production are citrus orchards. Citrus represents one of the highest value crops in the area (7.43 percent of the total 2001 value) but represents only 2.53 percent of the total 2001 acreage in the Palo Verde Valley agriculture district. The investment required to get a citrus orchard to the production stage is substantial. Retirement of currently active citrus producing lands could be a substantial economic impact to agriculture in the area.

Since specific lands for retirement or rotational fallowing have not been identified, it is not known if the WCOP would have a significant adverse impact on Prime Farmland or Farmland of Statewide Importance, as shown on the Department of Conservation (DOC) Important Farmland Map for eastern Riverside County. Similarly, the potential impact on any Williamson Act contract lands is unknown at this time. The Applicant has stated that Prime

Farmlands, Farmlands of Statewide Importance[1], and lands included in a Williamson Act Preserve would not be included in the WCOP. However, Staff is uncertain as to how the WCOP would conserve water, since irrigated farmland in the Palo Verde Valley area is typically classified in the Important Farmland Map categories and is often under Williamson Act contract. (FSA, pp. 4.5-17-18)

MITIGATION:

- ☑ If the WCOP causes the permanent retirement of irrigated farmland, the Project Owner shall mitigate at a one-to-one acre ratio conversion of productive farmland by payment of a mitigation fee or acquisition of an agricultural easement. Condition: **LAND-3**.

Cumulative Impacts

Cumulative land use impacts may occur when a project has effects that are individually limited but may be considerable when viewed together with effects of related new residential, commercial, and industrial projects.

The Imperial Irrigation District (IID) is overseeing the Desert Southwest Transmission Line Project (DSWTP), a proposed new 118-mile transmission line from Buck Boulevard Substation (on the BEP I site) to the Southern California Edison Company's Devers Substation, approximately 10 miles north of Palm Springs. BEP II would connect with the DSWTP at the Buck Boulevard Substation.

The DSWTP would be located entirely in a BLM-designated corridor. The project area is generally rural desert land with large amounts of undeveloped open space areas. The DSWTP and two other alternatives travel through or are adjacent to seven incorporated cities and several unincorporated communities in Riverside County. It is not clear from available documentation how many residential units and commercial buildings, and the amount of residentially and commercially zoned vacant property would be impacted by the DSWTP project. However, because BEP II does not have an impact on residential or commercial units and vacant property, any such impact by the DSWTP would not be a cumulative impact in combination with BEP II. (FSA, pp. 4.5-14-15)

Portions of the DSWTP and all other alternatives would travel through irrigated, productive farming areas. However, Energy Commission staff believes the available documentation does not specify the amount of Prime and other Important Farmland that would be affected. DSWTP transmission lines with periodic transmission tower structures could cross prime and other Important Farmlands.

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1 Farmland of Statewide Importance is similar to Prime Farmland but with minor shortcomings, such as greater slope or less capacity to hold and store moisture. Lands of Statewide Importance must have been in production of irrigated crops at some time during the update cycles prior to the mapping date.

Growth Inducing Impacts
The region in which the BEP II site is located is sparsely populated and exhibits fairly low growth potential compared to the rest of Riverside County. There is continued potential for tourist trade and recreation/destination traffic associated with the Colorado River; active freight rail service, and possible expansion of the Blythe Airport.

In general, power plants do not, in and of themselves, induce growth in the area where they are built. In the case of BEP II, the project may: 1) displace imported electricity, thereby not resulting in any additional electricity or growth effects in Blythe, and/or 2) send any surplus electricity outside of Blythe if there is not enough demand within Blythe.

Since BEP II would be an industrial use within the plan area and conforms to the General Plan's Heavy Industrial designation, the General Plan has analyzed any growth-inducing impacts associated with BEP II as part of the industrial build-out. (FSA, p. 4.5-16)

Findings

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to land use and all potential land use impacts will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

LAND-1 The project owner shall prepare a site development plan that complies with the applicable design criteria and performance standards for the General Industrial District set forth in the City of Blythe Zoning Ordinance. The site development plan must contain the following features:

- Setbacks (i.e. yard area requirements) for structures;
- Building elevations;
- Landscaping requirements;
- Temporary and permanent signs for project identification; permanent and construction phase signs; and
- Permanent parking lot design, showing the quantity and dimension of spaces.

Following preparation of the above site development plan, the project owner shall design and construct the project consistent with the applicable design criteria and performance standards for the General Industrial District set forth in the City of Blythe Zoning Ordinance.

Verification: At least 60 days prior to the start of construction, the project owner shall concurrently submit the site development plan to the CPM and the City of Blythe. The material submitted to the CPM must include documentation that the City of Blythe has been given the opportunity to review and comment on the plan and its compliance or conformance with the above-referenced requirements.

LAND-2 The project owner shall provide descriptions of the final laydown/staging areas identified for project construction to the Director of the City of Blythe Development Services Department for review and comment, and the CPM for review and approval. The description shall include:

(a) Assessor's Parcel numbers;
(b) addresses;
(c) land use designations;
(d) zoning;
(e) site plan showing dimensions;
(f) owner's name and address (if leased); and,
(g) duration of lease (if leased).

<u>Verification:</u> The project owner shall provide the specified documents to the CPM at least 30 days prior to the start of any ground disturbance activities.

LAND-3 If the WCOP involves permanent transfer of irrigation water previously used for land designated as either Prime Farmland or Farmland of Statewide Importance as defined by the Department of Conservation (Designated Farmland), the project owner shall mitigate at a one-to-one acre ratio for the conversion of farmland in the fulfillment of the WCOP through permanent retirement (time of the expected life of the project or greater) by implementing one or more of the following strategies:

1) a mitigation fee payment to the Riverside County agricultural land trust or the American Farmland Trust consistent with a prepared Farmlands Mitigation Agreement. The payment amount shall be determined by contacting the local assessor's office to determine the assessed value for the acreage of productive agricultural land retired by the WCOP, or by a real estate appraiser selected by the project owner and approved by the CPM.

2) securing the acquisition of an agricultural easement for other farmland (retired or fallow land that has been actively irrigated within the past five years within the Palo Verde Irrigation District Service area). Easements for irrigated farmland would be acquired based on the California Department of Conservation's Important Farmland Classification Map, but in no case shall be less than a 1:1 ratio. The program will involve approximately 726 acres assuming an accounting basis of consumptive water use of 4.2 acre-feet per acre.

<u>Verification:</u> Thirty (30) days prior to start of construction, the project owner shall provide in its monthly compliance reports a discussion of any land and/or easements purchased in the preceding month by the trust with the mitigation fee money provided, and the provisions to guarantee that the land managed by the trust will be farmed in perpetuity. This discussion must include the schedule for purchasing the same acreage of Designated Farmland as retired by the WCOP and/or easements within one year of start of construction as compensation for the acreage of Designated Farmland to be converted by the WCOP.

LAND-4 The project owner shall comply with the Riverside County Airport Land Use Commission conditions related to land use conveyance of an avigation easement to the Blythe Airport for all portions of the project including offsite power lines and pipelines within the Airport Influence Area.

Verification: At least 60 days prior to the start of construction of the power plant or any other facilities associated with the project, the project owner shall submit to the CPM a copy of the aviation easement showing proof of recordation with the Riverside County Recorder.

LAND-5 The project owner shall obtain the necessary approval(s) from the City and complete any lot merger or lot line adjustments necessary to ensure that the proposed project, including associated facilities and improvements, but excluding linear facilities, will be located on a single legal lot and owned by one entity. The BEP II facilities shall be constructed substantially as shown on the drawings submitted to and approved by the City of Blythe. It shall remain a single lot for the life of the power plant.

Verification: At least 30 days prior to the start of construction, the Project Owner shall provide the CPM with proof of completion of the above adjustments or satisfactory evidence that no such adjustments are necessary. Prior to submitting an application to the City, the project owner shall submit the proposed lot configuration to the CPM for review and approval.

LAND-6 The proposed water conservation offset program shall not retire lands in the Palo Verde Valley (Priority 1 Lands) designated as Prime Farmlands or Farmlands of Statewide Importance as defined by the Department of Conservation, or lands included in a Williamson Act Preserve. Fallowing or retirement of farmlands shall not violate any provision of a Williamson Act Contract. Lands selected for retirement on the Mesa shall not include lands currently involved in active orchard crop production.

Verification: At least 60 days prior to implementation of the Water Conservation Offset Program (WCOP), the project owner shall submit detailed information to the CPM regarding the lands involved in the WCOP, including: 1) location and assessor parcel number, 2) Department of Conservation Important Farmland Program Classification, 3) crop and cultivation history, and 4) Williamson Act Preserve and contract status. If the program will fallow or retire any lands under Williamson Act contract, the project owner shall provide documentation that such fallowing or retirement has been reviewed and approved by Riverside County Planning Department and does not violate any provision of a Williamson Act contract. Any WCOP agreements that are altered or added to the program shall be submitted to the CPM at least 30 days prior to taking effect.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

LAND USE

APPLICABLE LAW	DESCRIPTION
FEDERAL	
Federal Aviation Administration	Interruption of flight patterns by exhaust stacks.
STATE	
Subdivision Map Act (Pub. Res. Code §§ 66410-66499.58	The Subdivision Map Act provides procedures and requirements regulating subdivisions and the determining of parcel legality. This Act vests regulation and control of the design and improvement of subdivisions in local municipalities.
Public Utilities Code §§21402 & 21403	Prohibits any use of land that would interfere with flight.
Public Utilities Code § 21676	Authorizes a local jurisdiction to overrule a determination by the Airport Land Use Commission of the nonconformity of a proposed local action related to the local airport Comprehensive Land Use Plan, upon the making of required findings.
LOCAL	
Riverside County Comprehensive General Plan (RCCGP) Land Use Element	States the primary policy for implementing the development and conservation goals of the County's General Plan, including land use compatibility, population levels, public facility levels, environmental constraints and community policies. The Land Use Element contains policies specific to the Palo Verde Valley Area.
Riverside County Comprehensive General Plan (RCCGP) Environmental Hazards and Resources Element	Contains an open space and conservation inventory and related map, which delineate those areas that have significant open space or conservation value. These areas may include agricultural lands, parks and recreation areas, vegetation resources, wildlife resources, scenic highways, historic resources, energy resources, fire hazard areas, seismic/geologic hazard areas, slope areas, flood hazard areas, noise impacted areas and other natural resources and hazards. Mapped land uses include open space, recreation, agriculture, mining, research and related compatible land uses
Comprehensive Land Use Plan for Blythe Airport,	The CLUP is to protect and promote safety and welfare of residents of the airport vicinity and users of the airport while

Riverside County, (CLUP)	ensuring the continued operation of the airport. Where local general plans or specific plans are not consistent with the CLUP, State law enables the ALUC to require the local agencies to submit all development actions, regulations, and permits to the ALUC for review.

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NOISE – Summary of Findings and Conditions

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<tr><th></th><th>POWER PLANT SITE</th><th>CUMULATIVE IMPACTS</th><th>LORS COMPLIANCE</th></tr>
<tr><td rowspan="2">Loudness/
Time of Day</td><td>MITIGATION</td><td>MITIGATION</td><td>YES</td></tr>
<tr><td colspan="3">
<u>Construction</u>: Construction activities may cause noise disturbances to nearby residences. It is necessary to clear the steam pipes of debris that would damage the steam producing equipment. This flushing process, known as a steam blow, is traditionally accomplished by venting high-pressure steam to the atmosphere, which would produce a very loud noise at the nearest residential receptor.

MITIGATION:
☑ The Project Owner shall notify neighboring residents and business owners of impending construction at the power plant site and disseminate a telephone “hotline” number to report any undesirable noise conditions. Condition: NOISE-1.
☑ The Project Owner shall create a noise complaint process through which it will attempt to resolve all noise complaints. Condition: NOISE-2.
☑ The Project Owner shall comply with construction time-of-day restrictions. Condition: NOISE-8.
☑ The Project Owner shall use a muffler on the steam blow to meet maximum noise limit of 100 dBA at 100 feet for the high-pressure steam blow process. The Project Owner will notify affected neighbors prior to conducting steam blows. Conditions: NOISE-4 & NOISE-5.

<u>Operation</u>: During its operating life, the generating facility will represent essentially a steady, continuous noise source day and night. The noise emitted by power plants during normal operations is generally broadband, steady state in nature. Occasional short-term increases in noise level will occur as steam relief valves open to vent pressure, or during start-up or shutdown, as the plant transitions to and from steady-state operation.

MITIGATION:
☑ The Project Owner shall maintain a telephone “hotline” number to report any undesirable noise conditions for at least one year after operation begins. Condition: NOISE-1.
☑ The Project Owner shall create a noise complaint process through which it will attempt to resolve all noise complaints. Condition: NOISE-2.
☑ The Project Owner shall ensure that the project does not cause noise levels to exceed 49 dBA L_{eq} at the nearest residence. Condition: NOISE-6.
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	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Worker Noise:	**MITIGATION**	**None**	**Yes**
	Power plant noise can damage workers' hearing if not properly managed. **MITIGATION:** ☑ The Project Owner will implement a noise control program for employee noise exposure. Condition: **NOISE-3**. ☑ The Project Owner shall conduct an occupational noise survey and take action based upon its results. Condition: **NOISE-7**		
Vibration	**None**	**None**	**YES**
	The primary source of vibration noise associated with a power plant is the operation of the turbines. It is anticipated that the plant's turbines will be maintained in optimal balance to minimize excessive vibration that can cause damage or long term wear. Consequently, no excessive vibration would be experienced by adjacent land uses.		

NOISE – GENERAL

The construction and operation of any power plant creates noise and sound. Construction noise is a temporary phenomenon. Construction noise levels heard offsite would vary from hour to hour and day to day, depending on the equipment in use and the operations being performed.

The character and loudness of this noise, the times of day or night during which it is produced, and the proximity of the facility to any sensitive receptors are combined to determine whether the facility will meet applicable noise control laws or cause any significant noise impacts.

Sound associated with the operation of the project will be produced by the inlets, outlets, structures, motors, pumps and fans associated with the two gas turbines, the heat recovery steam generators, the electric generators, the transformers and the cooling towers. Essentially, project equipment will operate continuously and produce a steady sound 24-hours per day, seven days per week. Occasional short-term noise level increases will occur during plant start-up or shut down, during load transitions, and during opening of steam release valves for venting pressure. At other times, the plant will be shut down, producing less noise.

Loudness/Time of Day

Construction: The construction phase does not create long-term increases in noise levels. The potentials for speech interference during the daytime or sleep disturbance at night are the most appropriate criteria for assessing construction noise impacts. If the hourly average construction noise level during the day were to exceed 60 dBA Leq in an outdoor activity area near a residence, the construction noise would begin to interfere with speech communication.

In order to predict the likely noise effects of the project on adjacent sensitive receptors, the Applicant commissioned two ambient noise surveys in the area. The first survey was conducted November 2-3, 1999 as part of the environmental study for the BEP I AFC. The Applicant's noise survey monitored existing noise levels at the commercial/industrial building at 16275 Hobsonway, which is about 1,425 feet from the project boundary, and about 600 feet north of I-10. The nearest house is located farther from the project boundary, and closer to I-10, than the measurement site.

The calculated Ldn was 61.9 dB, and the calculated CNEL was 62.3 dB. In general, the environment in the immediate vicinity of the project site could be described as relatively quiet. The dominant background noise source was traffic on I-10, and the quietest period of the 24-hour day was during daytime hours (8 a.m. to 3 p.m.). The quietest period was also a period with low wind velocities. The average L90 during the quietest contiguous 4-hour period of the day was 43 dBA.

The second ambient noise survey was conducted over two periods in December 2003 and January 2004. This survey was performed at the nearest residence, at 16531 West Hobsonway.

During the noise measurements on January 19-21, 2004, the BEP I facility was not in operation. The lowest average background noise level over any four-hour period during that sample was 46 dBA (L90). During the noise measurements on December 19-23, 2003, BEP I was in operation, and the lowest average background noise level over any four-hour period was 47 dBA (L90). The operation of BEP I therefore does not appear to cause a significant change in ambient noise levels at the nearest residence. The dominant background noise source at this residence was traffic on I-10. Since the residence is closer to I-10 than the measurement site employed in 1999, the background noise levels at the residence are slightly higher than at the 1999 measurement site.

Construction noise is usually considered a temporary phenomenon. Sensitive receptors near the plant site could be affected by noise from these activities. 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 is commonly exempt from enforcement by local ordinances. Riverside County regulates the permissible hours of construction, but does not have any specific noise limits during those hours.

The Applicant's construction noise analysis for the worst-case noise sources indicate that the maximum noise level predicted at the nearest residence would be about 56 dBA, including ambient noise. The Applicant opined that, since this level of noise is close to the maximum average noise level at the nearest residence, the construction noise would likely be audible during traffic lull periods. There are no other noise-sensitive receptors within the range of distances where construction noise would be expected to be audible. (FSA, p. 4.6-7)

The changes in ambient noise levels would be of a temporary nature. The unmitigated increases in ambient noise levels due to construction are expected to be insignificant. The Applicant and Staff reached agreement on Condition of Certification **NOISE-8**, which establishes time-of-day restrictions for noisy construction and further agreed to Conditions **NOISE-1** and **NOISE-2** that govern notification and communication of noise complaints during construction.

MITIGATION:

- ☑ The Project Owner will notify neighboring residents and business owners of impending construction at the power plant site and disseminate a telephone "hotline" number to report any undesirable noise conditions. Condition: **NOISE-1**.
- ☑ The Project Owner will create a noise complaint process through which it will attempt to resolve all noise complaints. Condition: **NOISE-2**.
- ☑ The Project Owner shall comply with construction time-of-day restrictions for noisy construction. Condition: **NOISE-8**.

Steam Blows

Since the power plant will include heat recovery steam generators (HRSGs) to produce steam from the waste heat of the combustion turbines, it is necessary to clear the steam pipes of construction (welding) debris that would damage this equipment. This flushing process, known as a steam blow, is traditionally accomplished by venting high-pressure steam to the atmosphere.

Although there are low pressure and quieter steam blow processes, the Applicant plans to use the high-pressure steam blow process. The Applicant notes that no noise complaints have been received for BEP I. (FSA, p. 4.6-8) Condition **NOISE-4** establishes time of day and maximum steam blow levels to mitigate the greater noise of the high-pressure steam blow process. Further, Condition **NOISE-5** establishes a notification process to make neighbors aware of scheduled steam blows.

MITIGATION:

- ☑ The Project Owner shall use a muffler on the steam blow to meet maximum noise limit of 100 dBA at 100 feet for the high-pressure steam blow process. The Project Owner will notify affected neighbors prior to conducting steam blows. Conditions: **NOISE-4** & **NOISE-5**.

Operation: During its operating life, the generating facility will represent essentially a steady, continuous noise source day and night. The noise emitted by power plants during normal operations is generally broadband, steady state in nature. Occasional short-term increases in noise level will occur as steam relief valves open to vent pressure, or during start-up or shutdown, as the plant transitions to and from steady-state operation.

The Applicant conducted noise measurements at BEP I in March 2003, and performed acoustical calculations to describe typical facility noise emissions. The modeling assumed that the noise levels and frequency content of BEP I would be representative of the noise produced by the BEP II. The predicted BEP II power plant noise level would exceed the ambient noise level measured in 2003-2004 by about 3 dB. It would also exceed the estimated current ambient noise level (2003-2004 plus BEP I) by 2 dB.

Condition of Certification **NOISE-6** requires that the noise level produced by the BEP II plant operation not exceed 49 dBA L_{eq} at the nearest residence, which is the level predicted by the Applicant's modeling. The resulting increase above ambient noise levels, with and without operation of BEP I, would be barely perceptible, and would not be expected to be annoying. Noise due to the BEP II operations would not exceed the standards of the LORS at any sensitive receptor. (FSA, p. 4.6-10)

Noise levels generated during system start-up and shutdown may be elevated compared to steady-state operations, as steam relief valves may be employed for short periods under those conditions. The Applicant has indicated that the duration of start-up periods could be approximately three hours. The potentially significant noise sources during start-up would be the start-up steam system and the high-pressure steam bypass station. Based on the system design specifications, the predicted start-up steam vent noise levels would be in the range of 50 to 55 dBA at the nearest residence. Such releases are typically relatively short, in the range of a few minutes per occurrence. The predicted steam bypass station noise level would be about 39 to 44 dBA at the nearest residence; the event duration could be in the range of 30 minutes to one hour or more. No strong tonal noises or individual sounds, would be generated during the operation of the project. (FSA, pp. 4.6-10-11)

To ensure that no strong tonal noises are present and that intermittent noises are mitigated, Condition **NOISE-6** requires the applicant to ensure that there are no pure tones, and to mitigate the noise from steam relief valves.

MITIGATION:

- ☑ The Project Owner shall ensure that the project does not cause resultant residential noise levels to exceed 49 dBA L_{eq} at the nearest residence. Condition: **NOISE-6**.

Worker Noise

Power plant noise can damage workers' hearing if not properly managed. The Applicant recognizes the need to protect plant operating and maintenance personnel from noise hazards, and has committed to comply with applicable LORS. 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. The Applicant would implement a comprehensive hearing conservation program.

MITIGATION:

- ☑ The Project Owner will implement a noise control program for employee noise exposure. Condition: **NOISE-3**.
- ☑ The Project Owner shall conduct an occupational noise survey and take action based upon its results. Condition: **NOISE-7.**

Vibration

No pile driving is required in the construction of the project. (FSA, p. 4.6-7) The primary source of vibration noise associated with a power plant is the operation of the turbines. It is anticipated that the plant's turbines will be maintained in optimal balance to minimize excessive vibration that can cause damage or long term wear. Consequently, no excessive vibration would be experienced by adjacent land uses.

Cumulative Impacts

The AFC identified that the BEP II could contribute to cumulative noise impacts in the project study area. To ensure that the cumulative noise effect of BEP I and BEP II would be insignificant, Condition **NOISE-6** requires that the noise level produced by operation of the project will not exceed an hourly average noise level (L_{eq}) of more than 49 dBA, measured at any residence.

The electrical output of the plant will connect to the Buck Blvd. Substation, which in turn could be connected to the proposed Desert Southwest Transmission Project transmission lines. According to that project's draft EIR/EIS, the transmission line project could result in noise impacts due to construction, blasting, and noise due to corona discharge hum and onsite maintenance.

Construction noise impacts would be mitigated in the draft EIR/EIS by limits on the time of day for construction, and by requirements for adequate mufflers. Blasting impacts would be mitigated in the draft EIR/EIS by establishing limits on the time of day of blasting, by requiring notice to sensitive receptors when blasting is planned, and by requiring a blasting plan approved by the BLM.

Since corona discharge hum is predicted to be 44 dBA directly under the transmission lines during inclement weather, and 20 dBA in dry weather, it was not considered significant. Other operational noise such as vehicle traffic was also considered insignificant. No additional mitigation would be required. (FSA, pp. 4.6-11-12)

MITIGATION:

- ☑ The Project Owner shall ensure that the project does not cause noise levels to exceed 49 dBA L_{eq} at the nearest residence. Condition: **NOISE-6**.

Findings

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to noise and all potential noise impacts will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

NOISE-1 At least 15 days prior to the start of ground disturbance, the project owner shall notify by mail all residents within one-half mile of the site 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. 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.

<u>Verification:</u> Prior to ground disturbance, the project owner shall transmit to the CPM a statement 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-2 Throughout the construction and operation of the project, 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 Complaint Resolution Form, or 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;
- If the noise is project related, take all feasible measures to reduce the noise at its source; 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.

<u>Verification:</u> Within 5 business days of receiving a noise complaint, the project owner shall file with the City of Blythe Development Services Department, the Riverside County Planning Department, and the CPM a copy of the Complaint Resolution Form, documenting the resolution of the complaint. If mitigation is required to resolve a complaint, and the complaint is not resolved within a 3-business day period, the project owner shall submit an updated Complaint Resolution Form when the mitigation is implemented.

NOISE-3 The project owner shall submit to the CPM for review and approval an employee construction noise exposure control program. 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. The project owner shall make the program available to Cal-OSHA upon request.

NOISE-4 If a traditional high-pressure steam blow process is employed during construction, the project owner shall equip steam blow piping with a temporary silencer that quiets the noise of steam blows to no greater than 100 dBA measured at a distance of 100 feet. The project owner shall conduct steam blows only between 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 operation, to the CPM.

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-5 At least 15 days prior to the first steam blow(s), the project owner shall notify all residents or business owners within one 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 residences and businesses have been notified of the planned steam blow activities, including a description of the method(s) of that notification.

NOISE-6 The project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the noise level produced by operation of the project will not exceed an hourly average noise level (L_{eq}) of more than 49 dBA, measured at any residence.

No new pure tone components may be 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.
Within 30 days of the project's first achieving a sustained output of 80 percent or greater of rated capacity, the project owner shall conduct a 25-hour community noise survey at or near the residence at 16531 Hobsonway. The noise survey shall also include short-term

measurement of one-third octave band sound pressure levels to ensure that no new pure-tone noise components have been introduced. If the results from the noise survey indicate that the noise level due to the plant operations exceeds the noise standard listed above for any given hour during the 25-hour period, mitigation measures shall be implemented to reduce noise to a level of compliance with these limits. If the results from the noise survey indicate that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.

Verification: Within 30 days after completing the community noise survey, the project owner shall submit a summary report of the survey to the City of Blythe Development Services Department, to the Riverside County Planning Department, and to the CPM. Included in the post-construction survey 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-7 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 (Article 105) 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 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.

NOISE-8 Noisy construction or demolition work (that which causes off-site annoyance, as evidenced by the filing of a legitimate noise complaint) shall be restricted to the times of day below:

- High-pressure steam blows: 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.

- Other noisy work:
    - According to City of Blythe regulations and Riverside County Ordinance Chapter 15.04

Verification: The project owner shall transmit to the CPM in the first Monthly Construction Report a statement acknowledging that the above restrictions will be observed throughout the construction of the project.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

NOISE

APPLICABLE LAW	DESCRIPTION
FEDERAL	
EPA 1974 Noise Guidelines	Guidelines for State and Local Governments
HUD Circular 1390.2	Directions for noise levels at construction-site boundaries not to exceed 65 dBA for 9 hours in a 24-hour period.
29 CFR Section 1910.95 (OSHA Health and Safety Act of 1970)	Exposure of workers to over an 8-hour shift should be limited to 90 dBA.
STATE	
California Vehicle Code §23130 and 23130.5	Regulates vehicle noise limits on California Highways.
8 CCR §5095 et seq. (Cal-OSHA)	Sets employee noise exposure limits. Equivalent to Federal OSHA standards.
LOCAL	
Riverside County General Plan Noise Element	Contains standards, policies and procedures that are intended to minimize noise impacts to the community. The noise level standards for residential land uses are: Normally Acceptable: CNEL or Ldn up to 60 dB; Conditionally Acceptable: up to 70 dB CNEL or Ldn.
Riverside County Code	Construction within one-quarter mile of an occupied residence is prohibited between the hours of 6 p.m. and 6 a.m., except as allowed with the written consent of the building official.
City of Blythe General Plan (Draft) Noise Element	The City of Blythe is currently applying a draft Noise Element of the General Plan. The draft policy for new development of industrial or other noise-generating land uses prohibits development if resulting noise levels would exceed 60 dB Ldn or CNEL at the boundary of areas containing or planned and zoned for residential or other noise-sensitive land uses.

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PUBLIC HEALTH – Summary of Findings and Conditions

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS CONFORMANCE*
Construction Health Risks	**MITIGATION**	**None**	**YES**
	Large construction equipment potentially contributes to existing violations of state 24-hour PM_{10} standards. **MITIGATION:** ☑ To minimize PM_{10} emissions, the Project Owner shall require its construction contractors to minimize emissions from diesel powered earthmoving equipment. Condition **AQ-C5.** Grading and excavation activities potentially produce dust that can be transported off-site by wind. **MITIGATION:** ☑ To control airborne fugitive dust, the Project Owner shall water or apply chemical dust suppressants to disturbed areas, apply gravel or paving to traffic areas, and wash wheels of vehicles or large trucks leaving the site. Conditions: **AQ-SC3** & **AQ-C4**.		

Cancer Risks	**Insignificant**	**None**	**YES**
	EPA-approved modeling used for health risk assessment from non-criteria air pollutants finds a maximum exposure to the highest level of carcinogenic project pollutants for 70 years has a cancer risk of 0.298 in a million, below the 1 in a million benchmark for a potential health impact.		
Non-Cancer Risks	**MITIGATION**	**None**	**YES**
	EPA-approved modeling used for health risk assessment from non-criteria air pollutants finds an exposure to the highest level of project pollutants produces a chronic hazard index of 0.02 and an acute hazard index of 0.01. Both are well below a threshold hazard index of 1.0, and thus not a significant health impact. Non-criteria emissions from the cooling tower originate from contaminants in the cooling source water that become entrained in liquid water droplets emitted as cooling tower drift. The BEP II will use high efficiency drift eliminators that limit the amount of drift loss to approximately 0.0006 percent of the circulating water rate. Additionally, the possibility exists for bacterial growth, including Legionella, to be emitted in the cooling tower drift, unless sufficient biocides are maintained in cooling tower water **MITIGATION:** ☑ To minimize cooling tower drift, the Project Owner shall implement a drift eliminator inspection and maintenance program. Condition **PH-1.** ☑ The Project Owner shall prepare a bacterial control program to minimize Legionella bacteria from project cooling towers. Condition **PH-2.**		

PUBLIC HEALTH – GENERAL

Operating the proposed power plant would create combustion products and possibly expose the general public and workers to these pollutants as well as the toxic chemicals associated with other aspects of facility operations. The purpose of this public health analysis is to determine whether a significant health risk would result from public exposure to these chemicals and combustion by-products routinely emitted during project operations. The issue of possible worker exposure is addressed in the **WORKER SAFETY** section. Exposure to electric and magnetic fields (EMF) is addressed in the **TRANSMISSION LINE SAFETY AND NUISANCE** section.

The exposure of primary concern in this section is to pollutants for which no air quality standards have been established. These are known as non-criteria pollutants, toxic air pollutants, or air toxins. Those for which ambient air quality standards have been established are known as criteria pollutants. The criteria pollutants are also identified in this section because of their potentially significant contribution to the total pollutant exposure in any given area. Furthermore, the same control technologies may be effective for controlling both types of pollutants when emitted from the same source.

Construction Health Risks

Construction-phase impacts are those from human exposure to (a) the windblown dust from site grading and other construction-related activities and (b) emissions from the heavy equipment and vehicles to be used for construction.

The procedures for minimizing such dust generation are addressed in the **AIR QUALITY** section. As discussed in **WASTE MANAGEMENT** section, there is no widespread site contamination; thus there are no public health impacts anticipated from earth moving due to project construction.

The operation of heavy construction equipment will result in toxic emissions from diesel-fueled engines. Diesel exhaust is a complex mixture of many constituents that could cause adverse health impacts. However, the area of potential impact tends to be very close to the sources, due to the low height of the exhaust stacks. The nearest residence is about three-quarters of a mile to the southwest, with a few farm residences located more than one mile from the site. The nearest residential area is located about 2.5 miles to the southwest. Thus, there are no impacts to members of the public from the toxic constituents of diesel equipment exhaust. (FSA, p. 4.7-7)

The Applicant has agreed to a Condition of Certification that addresses construction equipment emissions. The measures to mitigate these emissions have been specified in Conditions **AQ-C3**. Since chronic health impacts are usually not expected from equipment emissions within the relatively short construction periods, only acute health effects could be significant with respect to the toxic exhaust emissions of concern in this analysis. Mitigation measures specified in Condition **AQ-C3** are sufficient to reduce these potential acute health effects to insignificance.

Cancer Risks

According to present understanding, cancer from carcinogenic exposure results from biological effects at the molecular level. Such effects are currently assumed possible from every exposure to a carcinogen. Therefore, Energy Commission staff and other regulatory agencies generally consider the likelihood of cancer as more sensitive than the likelihood of non-cancer effects for assessing the environmental acceptability of a source of pollutants. This accounts for the prominence of theoretical cancer risk estimates in the environmental risk assessment process.

For any source of specific concern, the potential risk of cancer is obtained by multiplying the exposure estimate by the potency factors for the individual carcinogens involved. Health experts generally consider a potential cancer risk of one in a million as the *de minimis* level, which is the level below which the related exposure is negligible (meaning that project operation is not expected to result in any increase in cancer). Above this level, further mitigation could be recommended after consideration of issues related to the limitations of the risk assessment process.

The Applicant conducted a screening level health risk assessment for the project-related non-criteria pollutants of potential significance. The screening level assessment uses a U.S. EPA-approved ISCST3 dispersion modeling program, employing conservative assumptions to avoid underestimating actual risks. The cancer risk estimates from this analytical approach represent only the upper bound on this risk. The actual risk would likely be much lower. Thus, when a screening level analysis is less than 1 in a million, the potential cancer risk is insignificant and additional, more refined analysis is not warranted.

A risk estimate of 0.298 in a million was calculated for all the project's carcinogens from this screening level analysis. This screening level estimate suggests that the project's cancer risk would be negligible and is significantly less than the 10 in a million which staff considers as a trigger for recommending mitigation. This means that the proposed emission controls measures are adequate for the project's operations-related toxic emissions of primary concern in this analysis. (FSA, pp. 4.7-9-10)

Non-cancer Risk

The Applicant's health risk assessment also reviewed non-criteria pollutants with respect to non-cancer effects. A chronic hazard index of 0.02 was calculated for the project's non-carcinogenic pollutants considered together. Their acute hazard index was calculated to be 0.01. These indices are well below the levels of potential health significance (hazard index 1.0), indicating that no significant health impacts would likely be associated with the project's non-criteria pollutants. (AFC 5.16-44; FSA Public Health, p. 4.7-7.)

The acute hazard index at the point of maximum impact for substances that could cause short-term health effects is 0.013. This means that the air concentration to which the public is exposed is about 77 times lower than an air concentration that is considered safe for all parts of the population, including sensitive subgroups. With the acute hazard index well under the significance level of 1.0, no short-term health effects are expected from routine plant operation.

The chronic hazard index at the point of maximum impact for substances that could cause long-term health effects is 0.002, which means that the air concentration to which people are exposed is about 455 times lower than the "safe" level for all parts of the population. The chronic hazard index is well under the safe level of 1.0, culminating in no chronic health effects. Further, all maximum hazard locations are in undeveloped areas, distant from sensitive receptors. (FSA, p. 4.7-10)

Cooling Tower

Non-criteria emissions from the cooling tower originate from contaminants in the cooling source water that become entrained in liquid water droplets emitted as cooling tower drift. The BEP II will use high efficiency drift eliminators that limit the amount of drift loss to approximately 0.0006 percent of the circulating water rate, resulting in a drift rate of about 0.9 gallons per minute. This amount of water lost as liquid from the cooling towers is in contrast to the amount of water evaporated as steam, estimated to be around 1860 gallons per minute (gpm) for the main cooling tower and about 160 gpm for the inlet chilling cooling tower, depending on ambient temperatures. Steam emitted from the cooling towers is distilled water, and will not contain contaminants. Similarly, drift eliminators on the inlet air chiller cooling tower will reduce the cooling tower mist to approximately 0.2 gallons per minute based on a loss of 0.001 percent.

The drift eliminators must be properly installed and maintained in order to achieve efficient operation over the life of the facility. Following installation, proper maintenance includes periodic inspection and repair or replacement of any components found to be broken or missing. Condition **PH–1** will ensure the inspection and maintenance of drift eliminators.

MITIGATION:

☑ To minimize cooling tower drift, the Project Owner shall implement a drift eliminator inspection and maintenance program. Condition **PH-1.**

In addition to being a source of potential toxic air contaminants, the possibility exists for bacterial growth to occur in the cooling tower, including Legionella. Legionella is a bacterium that is ubiquitous in natural aquatic environments and is also widely distributed in man-made water systems. It is the principal cause of legionellosis, otherwise known as legionnaires' disease, which is similar to pneumonia. Transmission to people results mainly from inhalation or aspiration of aerosolized contaminated water. Untreated or inadequately treated cooling systems, such as industrial cooling towers and building heating, ventilating, and air conditioning systems, have been correlated with outbreaks of legionnaire's disease.

In 2000, the Cooling Technology Institute (CTI) issued its report and guidelines for the best practices for control of Legionella. The CTI found that 40-60 percent of industrial cooling towers tested were found to contain Legionella. To minimize the risk from Legionella, the CTI noted that consensus recommendations included minimization of water stagnation, minimization of process leads into the cooling system that provide nutrients for bacteria, maintenance of overall system cleanliness, the application of scale and corrosion inhibitors as appropriate, the use of high-efficiency mist eliminators on cooling towers, and the overall general control of microbiological populations. Good preventive maintenance is very important in the efficient operation of cooling towers and other evaporative equipment (ASHRAE 1998). Preventive maintenance includes having effective drift eliminators, periodically cleaning the system if appropriate, maintaining mechanical components in working order, and maintaining an effective water treatment program with appropriate biocide concentrations. Most water treatment programs are designed to minimize scale, corrosion, and biofouling and not to control Legionella.

The efficacy of any biocide in ensuring that Legionella growth is kept to a minimum is contingent upon a number of factors including, but not limited to, proper dosage amounts, appropriate application procedures and effective monitoring. Condition **PH-2** requires the project owner to prepare and implement a biocide and bacterial control program. The program would ensure that proper levels of biocide and other agents are maintained within the cooling tower water at all times, that periodic measurements of Legionella levels are conducted, and that periodic cleaning is conducted to remove bio-film buildup. An aggressive antibacterial program coupled with routine monitoring and bacteria removal, the chances of Legionella growing and dispersing would be reduced to insignificant. (FSA, pp. 4.7-10-11)

MITIGATION:

☑ The Project Owner shall prepare a bacterial control program to minimize Legionella bacteria from project cooling towers. Condition **PH-2.**

Cumulative Impacts

Elevated concentrations of toxic air contaminants from stationary sources tend to be localized, and cumulative risks are likely to occur only when multiple facilities with substantial low-level emissions are immediately adjacent to, or very close to, one another. The closest major stationary sources are BEP I and the Southern California Gas Company's compressor station.

Conditions are not conducive for the potential mingling of the emissions from the compressor station and BEP II, because of the extended distance and differences in elevation between the station and BEP II and the general prevailing wind direction. Consequently, emissions for the compressor station were not included in the cumulative health risk assessment. Instead, the risk assessment was performed using emission calculations from only BEP I and BEP II. The cumulative excess lifetime cancer risk is estimated to be 0.73 in a million and the cumulative chronic and acute non-cancer hazard indices are 0.005 and 0.027, respectively. The levels are well below their significance levels, and do not suggest any cumulative health impacts to be significant. (FSA, p. 4.7-12)

Finding

With the implementation of the Conditions of Certification in other sections of this Decision, the project conforms with applicable laws related to public health, and all potential adverse impacts to public health will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

PUBLIC HEALTH-1 The project owner shall perform a visual inspection of the cooling tower drift eliminators once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to initial operation of the project, the project owner shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminator and certify that the installation was performed in a satisfactory manner. The CPM may, in years 5 and 15 of project operation, require the project owner to perform a source test of the PM_{10} emissions rate from the cooling tower to verify continued compliance with the vendor guaranteed drift rate.

Verification: The project owner shall include the results of the annual inspection of the cooling tower drift eliminators and a description of any repairs performed in the next required annual compliance report. The initial compliance report will include a copy of the cooling tower vendor's field representative's inspection report of the drift eliminator installation. If the CPM requires a source test as specified in Public Health-1, the project owner shall submit to the CPM for approval a detailed source test procedure 60 days prior to the test. The project owner shall incorporate the CPM's comments, conduct testing, and submit test results to the CPM within 60 days following the tests.

PUBLIC HEALTH-2 The project owner shall develop and implement a Cooling Water Management Plan to ensure that the potential for bacterial growth in cooling water is kept to a minimum. The Plan shall be consistent with either Staff's "Cooling Water Management Program Guidelines" or with the Cooling Technology's Institute's "Best Practices for Control of Legionella" guidelines.

Verification: At least 30 days prior to the commencement of cooling tower operations, the Project Owner shall provide the cooling water management plan to the CPM for review and approval.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

PUBLIC HEALTH

APPLICABLE LAW	DESCRIPTION
FEDERAL	
Clean Air Act, §109 and 301(a). 42 USC §7401 et seq. and 40 CFR 50	Established air quality standards to protect the public health from exposure to air pollutants.
Clean Air Act §112(g), 42 USC §7412, and 40 CCR 63	Requires review of new or modified sources prior to promulgation of the standard and establishes emissions standards for HAP from specific source types including gas turbines. THE APPLICANT will not be a major source of HAP and hence is not subject to these provisions at this time.
STATE	
Health and Safety Code §25249.5 et seq. (Safe Drinking Water and Toxic Enforcement Act -– Proposition 65)	Requires posting of facilities that have chemicals known to cause cancer and public notification of significant risks.
Health and Safety Code §39650-39625	Provides for a special statewide program directed by the ARB to evaluate the risks associated with emissions of chemicals designated as TAC and to develop and mandate methods to control these emissions.
Health and Safety Code §44300 et seq. (Air Toxics “Hot Spots” Information and Assessment Act –AB 2588)	Requires facilities that emit listed criteria or toxic pollutants to submit emissions inventories to the local air district. Such facilities may also be required to conduct a health risk assessment.

SOCIOECONOMICS – Summary of Findings and Conditions

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Employment	**None**	**None**	**YES**
	Construction: The construction workforce will peak at 387 workers and average between 200 to 300 workers. If additional workers are required, the project could draw from population centers in the region such as Las Vegas, Yuma, and Phoenix. Most of the workforce will be within a one-way commute time of two hours from the plant site. The project will benefit local employment directly. Operation: About 20 permanent workers will be needed to maintain and operate the project (12 to 14 operating technicians, 3 to 4 maintenance technicians and 3 to 4 administrators). This number of employees required for operation of BEP II would not cause a significant impact on the local labor force.		
Housing	**None**	**None**	**YES**
	Construction: Most of the construction workforce, peaking at 387 workers during the 20-month construction period, is expected to commute to the project. There are sufficient housing resources for any non-commuting workers including residential housing, hotels, and motels. Operation: The operation workforce is expected to commute to the project. There are sufficient housing resources for any new permanent employees to relocate to the project without impacting housing in the study area.		
Schools	**CONDITION**	**None**	**YES**
	Construction: Most of the construction workforce is expected to commute to the project. There would be no impact to the schools in the School District. Operation: Families of new fulltime operation employees may move into the project area and enter local schools without causing an impact to existing schools. A one-time school impact fee will be assessed on the project. **CONDITION:** ☑ The Project Owner shall pay a one-time school impact fee. Condition: **SOCIO-1**		

Utility/Public Services	**None**	**None**	**YES**
	Construction: Construction is not expected to create an additional demand for utilities, including landfill disposal or wastewater treatment. Operation: The operation of the power plant is not expected to create an additional demand for public services.		
Economy/ Government Finance	**None**	**None**	**YES**
	Construction: The total construction payroll for the power plant is estimated to be \$60 to \$65 million. The cost for locally purchased materials and supplies is estimated to be approximately \$5 - 10 million. Sales tax in Riverside County is 7.75 percent, of which the City of Blythe would receive one percent. Operation: Operation payroll is approximately \$1.0 million per year. Periodic major maintenance will spend \$1.5 million locally.		
Environmental Justice	**None**	**MITIGATION**	**YES**
	Minority/Low Income Population: The people of color within a 6-mile area total 7,216, or 59.29 percent of the total population. The low-income population is 2,046 persons, or 20.1 percent. Disproportionate Impacts: There are no significant project-related unmitigated adverse environmental or public health impacts. Potential air quality, public health, land use, and hazardous materials handling impacts to the public have been mitigated to less than significant through the Conditions of Certification in this Decision. While the project overall will result in a net increase of jobs, the voluntary Water Conservation Offset Plan contributes slightly to a pre-existing trend of the loss of farmworker jobs. The Applicant shall prepare a plan to address the farming sector economic impacts in consultion with stakeholders in the local area. The plan may coordinate with or complement the efforts resulting from the MWD mitigation fund. As a result, there are no significant cumulative project impacts, nor significant adverse impacts that fall disproportionately upon minority or low-income populations. **MITIGATION:** ☑ The project owner shall prepare a plan to address economic impacts to the farming sector from the WCOP and create a \$198,000 fund to implement any plan measures. Condition: **SOCIO-2**		

SOCIOECONOMICS – GENERAL

The socioeconomic impact analysis evaluates the potential direct and cumulative project-induced impacts on community services and/or infrastructure including schools, medical and protective services and related community issues such as environmental justice.

Employment

The AFC estimates that project construction activity will occur over 20 months. The labor force required for construction of the BEP II includes boilermakers, carpenters, electricians, ironworkers, laborers, millwrights, operators, pipefitters and others. The employed force would include both skilled and non-skilled workers. Based on occupational employment projections by the California's Employment Development Division there are sufficient skilled laborers for project construction. The labor force for construction of BEP II is expected to peak in the 12th month after the start of construction at 387 workers.

If additional workers are required, the project could draw from population centers in the region such as Las Vegas, Yuma, and Phoenix. Therefore, sufficient workers for construction of the BEP II are available within the general area. Most of the workforce will be within a one-way commute time of two hours from the plant site. The demand for skilled laborers should not result in a community labor shortage.

During operation of the project, about 20 permanent workers will be needed to maintain and operate the project (12 to 14 operating technicians, 3 to 4 maintenance technicians and 3 to 4 administrators). This number of employees required for operation of BEP II would not cause a significant impact on the local labor force. (FSA, pp. 4.8-3-4)

Housing

The BEP II could cause a tight housing market during construction if a large number of the workers relocate to the area. However, the Blythe area has supported a labor force for the construction of two prisons, Ironwood State Prison, which opened in February 1994, and Chuckawalla Valley Prison, which opened in December 1988, and BEP I. During the construction of these projects there was a maximum of 250 to 300 construction workers involved. There was no noticeable shortage of housing for these workers during construction. Many of the workers brought recreational vehicles (RV) with them and took advantage of the many RV parks in the area for housing during construction.

The most current available data (March 2002) from the Department of Finance (DOF) show that there were about 595,682 total housing units in Riverside County, with a vacancy rate of 13.4 percent. For the same period of time, the DOF estimated about 4,840 total housing units in Blythe, with a vacancy rate of 16.1 percent. Residential construction in the Blythe area includes 23 motels with about 1,100 rooms, over 300 mobile home spaces, over 600 RV spaces, and condominiums and apartments since the two prisons opened.

There are an additional 78 motels within 65 miles of Blythe, which would result in a commute of one hour or less for workers using these facilities. The lodging combination of housing, apartments, motel/hotel rooms, and RV spaces available to non-local construction and operation workers for this project should be sufficient.

Those employees seeking long-term residences could take advantage of new housing development that has been occurring within the City. The long-term operations of the facility would result in only a small increase in population with only 20 full-time employees required to operate the facility.

One possible concern for short-term housing is the influx of visitors during the winter. The population in the Palo Verde Valley triples during the winter season due to visitors attracted to the area because of its warm climate. A majority of the individuals coming to the area during the winter season typically use motor homes, trailers, and campers for their accommodations. Any potential housing needs for the BEP II construction workforce can be met by the City of Blythe and surrounding areas. (FSA, pp. 4.8-4-5)

Schools

The Palo Verde Unified School District experienced its peak enrollment of 4,050 students during the 1994-1995 school year. Since that time, school enrollment has declined approximately 1.5 percent annually. Current enrollment is about 3,677 students.

Construction of the proposed project is not expected to result in significant population changes for the school system as most of the construction workers are expected to commute to the work site. The operation of the BEP II will require a small work force of 20 employees. Therefore, if necessary, the Palo Verde Unified School District should be able to absorb additional students due to operation at the BEP II.

If the Palo Verde Unified School district should require additional facilities, the funding would be through either property taxes or statutory facility fees. The Palo Verde Valley Unified School District has in place an impact fee of $0.31 per square foot for new construction of commercial/industrial buildings. (FSA, p. 4.8-5)

CONDITION:

- ☑ The Project Owner shall pay a one-time school impact fee. Condition: **SOCIO-1**

Utility/Public Services

The project proposes to interconnect with the regional electric transmission grid at Western's Buck Boulevard Substation located within 800 feet of the BEP II power island. Natural gas would be supplied to the BEP II by the existing gas pipeline that serves BEP I. BEP II would use about 3,300 acre-feet of water annually supplied by on-site wells for cooling and other purposes. BEP II will handle its domestic wastewater and sewage treatment on-site during construction and operation. (FSA, p. 4.8-5-7)

Law Enforcement

The Blythe Police Department provides law enforcement for the City of Blythe. The Department is located at 249 North Spring Street, about five miles from the power plant. The current police department has a staff of 25 law enforcement officers. The Department estimates that emergency response time to the project would be about three minutes. Non-emergency response would be about seven minutes.

The City of Blythe has mutual aid agreements with other law enforcement organizations in the community. This includes the Riverside County Sheriff's Department, located at 260 North Spring Street in Blythe about five miles from the site. The Blythe station has 18 sworn full-time law enforcement officers and handles emergency calls for county residents in the general Palo Verde Valley. The estimated normal response time for a patrol vehicle to the BEP II would be about ten minutes. Other law enforcement services would be provided by the California Highway Patrol station located about five miles from the BEP II site at 430 South Broadway in Blythe.

Construction and operation of the project would not result in significant demands on law enforcement. (FSA, p. 4.8-7)

Fire Fighting

The Blythe Fire Department is located at 201 North Commercial Street. Its staff includes 30 trained volunteer firefighters in addition to one fulltime fire marshal. Fire fighting equipment consists of four fire engines, one 50-foot ladder truck, one water truck, one squad truck and one quick response vehicle. The Blythe Fire Department has a mutual aid agreement with the Riverside County Fired Department, which has two fires stations in Blythe, with a mix of fulltime and volunteer staff.

In October 2000, the City of Blythe and Riverside County performed a needs assessment to determine the incremental impacts of BEP I on the existing facilities. BEP I provided $450,000 for additional equipment and training. BEP II will not cause any new or cumulative impacts not previously addressed in the needs assessment arising from BEP I. (AFC, p. 7.6-8)

Medical/Hospital

Palo Verde Hospital is located at 250 North 1st Street in Blythe, about five miles east of the BEP II site. The hospital is a 55-bed acute care facility and has 24-hour emergency room service, 23 physicians/surgeons, six dentists, four optometrists, four chiropractors, and one podiatrist.

If required, other medical services are available in the area. Located approximately 30 miles from the BEP II in Parker, Arizona is the La Paz Medical Center. This is a full service hospital with eight doctors on staff, 39 beds and 24-hour emergency service. The community of Quartzsite has a clinic that offers daytime services and is associated with the La Paz Medical Center. Other medical facilities are located approximately 70 miles from the site, with the largest being the Yuma Regional Medical Center in Yuma, Arizona with 237 beds. These services are adequate to meet the medical service needs of the BEP II during construction and operation. (FSA, p. 4.8-7)

Economy/Government Finance

The City of Blythe and Riverside County, schools and other special districts in the BEP II Tax Rate Area will receive property tax revenue from the BEP II property. The BEP II will undergo annual reassessment at fair market value, and property tax collected will be distributed exclusively to the taxing jurisdictions in which the facility is located.

The local community will also receive a small amount of revenue from sales taxes on equipment, and material and supplies purchased during construction and operation. The Applicant estimates that the cost for material and supplies for construction will be $60 million. Of this amount, about $5 to $10 million of material and supplies will be purchased locally. Sales tax in Riverside County is 7.75 percent, of which the City of Blythe would receive one percent.

Impacts from construction include economic gains as a direct result of locally purchased materials and supplies, and construction payroll spending. Indirect or secondary impacts from construction could include increased employment for local workers in other areas of service, such as wholesale and retail, transportation, entertainment, and other business services.

In the AFC, the Applicant states that to maintain the BEP II during its operating life will require major maintenance for the facility every 3 to 4 years at an estimated cost of $10 million. Approximately 15 percent, or $1.5 million of this would be spent locally. Operation of the BEP II will require 20 full-time employees. As stated in the AFC, an employee's annual salary will average about $50,000, and will result in an average annual operating payroll of $1.0 million. (FSA, p. 4.8-8)

Environmental Justice

Presidential Executive Order 12898, entitled "Federal Actions to address Environmental Justice (EJ) in Minority Populations and Low-Income Populations," focuses federal attention on the environment and human health conditions of minority communities and calls on agencies to achieve environmental justice as part of this mission. The order requires the US Environmental Protection Agency (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, the Energy Commission follows the U.S. Environmental Protection Agency's guidance in conducting a two-step environmental justice analysis. The analysis assesses:

- Whether the population in the area potentially affected by the proposed project is more than 50 percent minority and/or low-income, or has a minority or low-income population percentage that is meaningfully greater than the percent of minority or low income in the general population, or other appropriate unit of geographic analysis; and
- Whether significant environmental impacts are likely to fall disproportionately on the minority and/or low-income population.

Commission staff determined the affected area for this environmental justice analysis to be the area within a six-mile radius of the proposed project site. This area corresponds to the area analyzed for potential air quality and public health impacts.

Updated census block data were reviewed to assess the demographic profile within that six-mile radius of the proposed power plant site. The population within this area totals 12,170. The people of color within this area total 7,216, or 59.29 percent of the total population. In addition, there are multiple census blocks with greater than 50 percent minority populations within the six-mile radius.

BEP I and BEP II are located about two miles from Mesa Verde/Nicholls Warm Springs, a small, unincorporated residential and largely Spanish-speaking community in the Palo Verde Mesa. Residents of this community and Blythe actively participated in the workshops and hearings for BEP I. Some residents of Blythe became intervenors in BEP I and are currently intervenors in BEP II. Although concerns for the health and well-being of the community expressed by the intervenors in BEP I included air quality impacts, their primary concern was the economic and environmental impacts associated with pumping groundwater. Despite the concerns of the community, the Commission found that all environmental issues had been analyzed and mitigated to a level below significance. To date, the concerns raised by intervenors in BEP II involve depletion of water in the Mesa Verde aquifer, air pollution, loss of citrus orchards and farm worker jobs, destruction of ancient and indigenous sites, and impacts to biological resources. (FSA, p. 4.8-9)

Census 2000 shows that the data set “Population for Whom Poverty Is Determined” totals 9,933 persons. Of these, 2,046 persons, or 20.1 percent, are below the poverty level. Federal guidance does not give a percentage of population threshold to determine when a low-income population becomes recognized for an environmental justice analysis. The Energy Commission uses the same greater than 50 percent threshold that is used for minority populations, as well as a “meaningfully greater” percentage population. However, 20.1 percent of the population that is below the poverty level indicates a high degree of poverty in the six-mile radius. (FSA, p. 4.8-10)

The minority population and low-income population within the six-mile radius are 59.29 percent and 20.1 percent, respectively. Based on the foregoing socioeconomic analysis, the proposed project would not result in significant, adverse socioeconomic impacts to housing, schools, public services, police and fire protection, and fiscal resources.

<u>Farm Sector Job Loss from the WCOP</u>

BEP II would use about 3,300 acre-feet of water annually supplied by on-site wells for cooling and other purposes. BEP II is proposing a voluntary Water Conservation Offset Program to retire or fallow lands within the Palo Verde Irrigation District's (PVID) service area that are or have been irrigated within the past five years. To offset project groundwater use, the WCOP would fallow about 786 acres of irrigated farmland every year for the life of the project.

To assess the potential impacts of the WCOP, Staff reviewed the 2002 *Socioeconomic Assessment of the Proposed Palo Verde Irrigation District Land Management, Crop Rotation and Water Supply Program* (M. Cubed report). Although PVID's proposed program would provide considerably more water for non-agricultural uses than the WCOP (about 25,000 to 110,000 acre-feet per year), the study area for both programs is the same geographic area. Staff's concern is the potential for job loss in the farm labor, farm services, and farm supply sectors resulting from removing 786 irrigated acres from production to allow agricultural water to be used for non-agricultural purposes.

For the PVID program, the M. Cubed report performed an input/output analysis using an Impact Analysis for Planning (IMPLAN) model that found the acreage-to-job loss ratio to be 0.00805. This number represents the number of full time equivalent (FTE) jobs lost from removing one acre from agricultural production. The job loss ratio depends upon the mix of crops taken out of production. In the M. Cubed report, the crops used to determine job loss were highly mechanized crops such as hay, alfalfa, cotton, and grains. If labor-intensive crops such as orchards, melons, citrus, and vegetable crops were taken out of production, the acreage to job loss ratio would be much higher.

The WCOP proposes to retire or fallow 786 acres within the PVID service area. Therefore, the resulting job loss would be 6.33 FTE jobs (0.00805 x 786) within the PVID. Staff does not consider this to be significant. Notwithstanding, Staff recommended a condition precluding acreage with labor intensive crops, such as orchards, melons, vegetables, and citrus from participating in the WCOP. Thus, only highly mechanized crops would be eligible for the WCOP. (FSA, p. 4.8-6, 7 & 14)

<u>Intervenor Garnica</u>

Intervenor Garnica presented multiple declarations from local farmworkers affected by the general decline in farm labor. The declarants also testified that the power plant has adversely affected them and their families economically. Displaced farmworkers have no training in any other vocational skill. Ms. Garnica, herself, testified that there used to be a training program in Blythe when the first BEP I project was proposed, and it was geared specifically for farmworkers. The program has ceased. So the Blythe projects are having a negative economic impact on low-income farmworkers. (8/2/05 RT 320:1 – 321:11)

<u>Applicant</u>

The Applicant testified that it concurs with Staff's testimony that the loss of 6.33 FTE jobs is not significant. Therefore, Applicant finds no impact that would warrant Staff's recommended prohibition against labor-intensive crops in the WCOP. The Applicant suggests that the Condition of Certification (**LAND-3**), requiring permanent farmland compensation for retired irrigated lands, will effectively mitigate potential farm labor job losses. Moreover, the project would create a net increase in Blythe area jobs and socioeconomic benefits versus the potential loss of 6 farmworker jobs. (Harvey, pp. 2-5)

In its Opening Brief, the Applicant notes that it has committed to giving 10 cents per construction labor man-hour to the local community college to be used in job training, providing an estimated $120,000. To address concerns in the community, the Applicant will conduct an outreach program to the farm labor community so that farmworkers know of and can participate in the training programs at the community college. The outreach program will include advertisement on Spanish-speaking radio station, passing out flyers in the Mesa Verde community, and notifying the Rural Assistance League or other farm labor organizations of the training opportunities at the community college. (Applicant Opening Brief, p 12 & 13)

Commission Discussion

The Commission does not believe that a crop-type limitation on the WCOP is warranted. It would likely undermine the water conserving purpose of the WCOP. Moreover, the loss of farm labor jobs in the Blythe area represents a larger existing trend, which is better addressed by retraining farmworkers than by the crop limitation. The WCOP programs in the PVID service area will accelerate the trend, so specifically the BEP II WCOP will contribute to a cumulative adverse economic effect on the farming sector and farm workers in particular. BEP II's funding of job training at the community college is laudable. The question for the Commission is whether it is effective in addressing impacts to the farming sector, which is a multifaceted impact to vendors, small business owners, as well as farmworkers.

MWD set up a $6 million fund to mitigate economic losses from its WCOP arising from its 100,000 acre-feet water transfer agreement with PVID. (8/2/05 RT 349:7-14) If the BEP II project owners were to establish a mitigation fund at a proportional rate ($60 per acre-foot), it would be $198,000. The Applicant's proposed contribution to the community college and proposed outreach appear to be approaching that sum anyway.

The Commission prefers that the Applicant's contributions and effort be part of a coordinated effort specifically to address the farming sector impacts from the WCOP. However, such an effort, if it exists at all, is in its earliest stages of discussion and planning. The MWD $6 million mitigation fund will undoubtedly propel attention and ultimately action to address this impact.

Consequently, the Commission directs the Applicant to prepare a plan to address the farming sector economic impacts from the WCOP. The Commission expects that the Applicant will consult with stakeholders in the local area, including MWD, the community college, and farmworker representatives in the preparation of the plan. The plan may coordinate with or complement the efforts resulting from the MWD mitigation fund. The Commission expresses its preference for retraining efforts to address these impacts, including specifically retraining for Spanish-speaking workers. The Commission also prefers that any measures be undertaken in the first five to ten years of project operation. The Applicant shall create a one-time $198,000 fund to implement its plan. The proposed $120,000 contribution to the community college may be credited toward that amount.

MITIGATION:

- ☑ The project owner shall prepare a plan to address economic impacts to the farming sector from the WCOP and create a $198,000 fund to implement any plan measures. Condition: **SOCIO-2**

Cumulative Impacts

Potential cumulative impacts from the WCOP are discussed above.

The potential for cumulative socioeconomic impacts exists when there are other projects proposed in the region that have overlapping construction schedules that could impact similar resources. Staff is currently reviewing the Blythe Energy Project Transmission Line (BEPTL) Petition for Post-Certification Amendment (99 AFC-8C) and expects the project to come before the Commission in the Fall of 2005. The 12-month construction phase would begin upon certification of the project. That applicant expects the peak construction labor force to total 162 workers. Despite the recent growth and developments in Riverside County, there is no shortage of available skilled construction workers in the County. No housing shortage was identified for BEP I and none is expected due to construction of BEP II. Therefore, construction and operation of the BEP II would not result in any significant cumulative impacts to housing and construction worker availability.

Findings

The project would not cause a significant adverse direct or cumulative impact on housing, employment, schools, public services or utilities. The project would have a temporary benefit to the City of Blythe and adjacent areas in terms of an increase in local jobs and commercial activity during the construction of the facility. The construction payroll and project expenditures would also have a positive effect on local and County economies. The estimated benefits from the project include increases in the affected area's property and sales taxes, general employment, and sales of services, manufactured goods, and equipment.

The project conforms to applicable laws related to socioeconomic matters and all potential socioeconomic impacts will be insignificant.

CONDITIONS OF CERTIFICATION

SOCIO-1 The project owner shall pay the statutory school impact development fee as required at the time of filing for the "in-lieu" building permit.

Verification: The project owner shall provide proof of payment of the statutory development fee to the Compliance Project Manager (CPM) in the next Monthly Compliance Report following the payment.

SOCIO-2 The project owner shall prepare a plan to address the farming sector economic impacts from the WCOP. The Applicant shall create a $198,000 fund to implement plan measures. The project owner's proposed $120,000 contribution to the community college may be credited toward that amount.

<u>Verification:</u> The project owner shall submit the plan to the CPM for review and approval at least six months prior to commercial operation. The plan shall contain, at a minimum, the specific activities to implement and a description of how each plan will be funded.

SOCIO-3 The project owner and its contractors and subcontractors shall recruit employees and procure materials and supplies within the Blythe Area, unless:

- To do so will violate federal and/or state statutes;
- The materials and/or supplies are not available;
- Qualified employees for specific jobs or positions are not available; or
- There is a reasonable basis to hire someone for a specific position from outside the local area.

<u>Verification:</u> At least five days prior to the start of construction, the project owner shall submit to the Energy Commission Compliance Project Manager (CPM) copies of guidelines stating hiring and procurement requirements and procedures. In addition, the project owner shall notify the Energy Commission CPM in each Monthly Compliance Report of any procurement of materials or hiring outside the local regional area that has occurred during the previous month. The Energy Commission CPM shall review and comment on the submittal as needed.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

SOCIOECONOMICS

APPLICABLE LAW	DESCRIPTION
FEDERAL	
Executive Order 12898	Executive Order 12898, “Federal Actions to address Environmental Justice (EJ) in Minority Populations and Low-Income Populations,” focuses federal attention on the environment and human health conditions of minority communities and calls on agencies to achieve environmental justice as part of this mission. The Order requires the US Environmental Protection Agency (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.
STATE	
California Government Code sec. 65995-65997	Includes provisions for levies against development projects in school districts. The local Unified School District will implement school impact fees based on new building square footage.
LOCAL	
None	

TRAFFIC & TRANSPORTATION – Summary of Findings and Conditions

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Congestion	**MITIGATION**	**None**	**YES**
	<u>Construction</u>: Commuting construction workers, estimated to peak at 387 workers for three months, will not cause significant congestion on the interstate highway or the local streets and intersections. Truck deliveries of construction equipment and supplies is estimated to peak at 25 deliveries per day during the peak months, which is within the design limits of the Interstate highways and local streets. To prevent construction worker and truck delivery congestion requires a Traffic Plan to time and coordinate project traffic. **MITIGATION:** ☑ The Project Owner shall prepare a Construction Traffic Control Plan to assure that construction does not create unacceptable congestion impacts. To achieve this goal, the Project Owner will schedule arrival and departure times, minimize lane closures and use traffic control, and assure access to residences and businesses during construction. Condition: **TRANS-5**. <u>Operation</u>: Operation of the generating plant would require a labor force of 20 full-time employees. The majority of the permanent workforce would reside in the greater Blythe area and their preferred route to work would be along I-10, with minimal impact.		

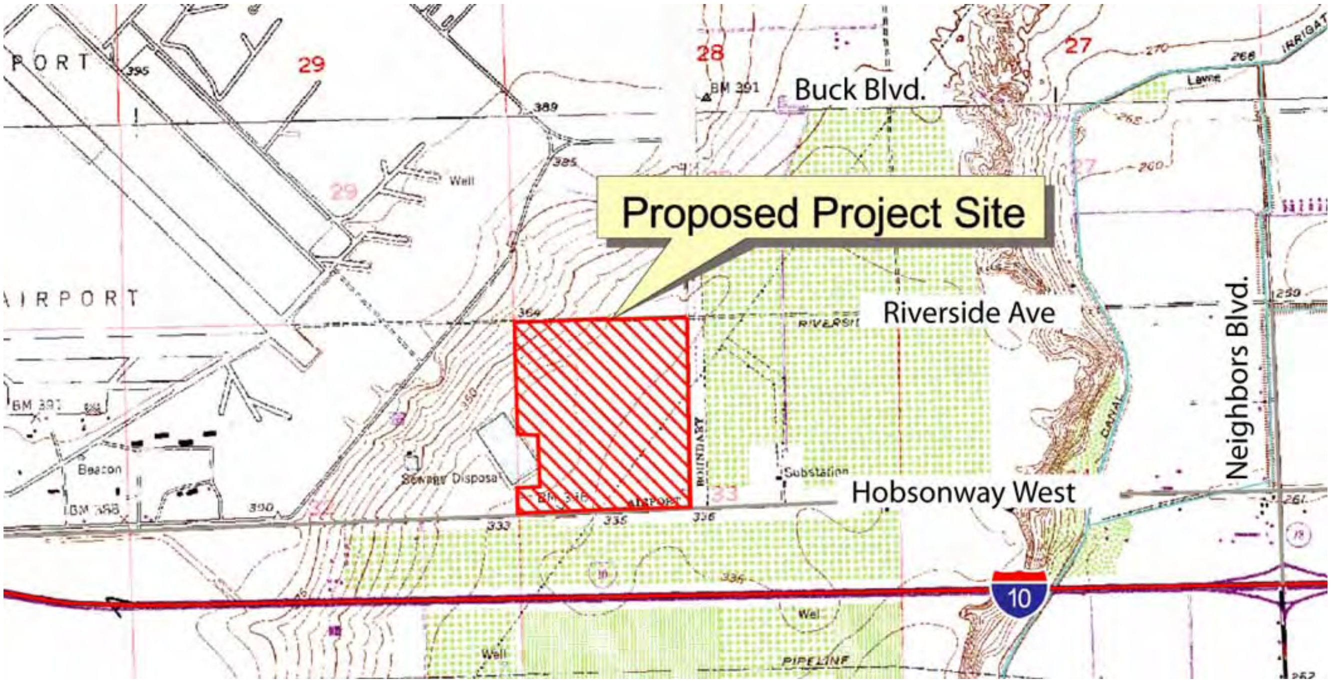
	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Safety	**MITIGATION**	**None**	**YES**
	Construction: Construction will require the use of large vehicles, occasionally including oversize or overweight trucks. Additionally, there will be deliveries to the power plant site of hazardous construction substances, such as gasoline, diesel fuel, oils, solvents, cleaners, paints, etc. **MITIGATION:** ☑ Caltrans permits control vehicle size and weight. Condition: **TRANS-1**. ☑ California Highway Patrol and Caltrans permits control transport of hazardous substances. Condition: **TRANS-3**. ☑ Encroachment permits shall be obtained and construction-impacted roadways will be restored to their pre-construction condition. Condition: **TRANS-2** and **TRANS-7**. Operation: The Applicant has estimated that there would be three truck round trips to the site daily, or 6 trips total, during plant operations. This addition to daily traffic will not significantly affect LOS levels. The transportation and handling of hazardous substances associated with project operation can increase roadway hazard potential. Deliveries of hazardous materials will be over pre-arranged routes selected for their safety features, including the absence of obstructions and curves, and minimal railroad traffic. Trucks and drivers will comply with federal and State regulations. **MITIGATION:** ☑ Hazardous materials haulers must be specially licensed by the California Highway Patrol. Condition: **TRANS-3;** See also **HAZARDOUS MATERIALS** section.		

	POWER PLANT SITE	CUMULATIVE IMPACTS	LORS COMPLIANCE
Aviation Safety	**MITIGATION**	**None**	**YES**
	Operation Turbulence caused by the project's thermal plumes could adversely affect flight operations at the Blythe Airport, particularly for student pilots. The Applicant has agreed to conditions creating broadcast notification to pilots of the plume hazard and changes to Airport flight operations to avoid the plumes. **MITIGATION:** ☑ The Project Owner shall not commence construction of BEP II until the following are accomplished: 1. A remark is placed on the Airport's Automated Surface Observation System (ASOS), or equivalent broadcast, advising pilots to avoid low-altitude direct overflight of the power plant; 2. The VFR traffic pattern to runway 26 is changed from left-hand turns to right-hand turns; and 3. A runway, other than runway 26, is designated as the primary calm wind runway. Condition: **TRANS-9**		
Parking	**MITIGATION**	**None**	**YES**
	Construction: Parking for construction worker vehicles and the laydown area for construction supplies and equipment would be provided on 76 acres on the western side of BEP II plant site, including 10 acres for additional laydown space on the eastern side of the site. **MITIGATION:** ☑ The Project Owner shall develop a construction worker parking and materials staging plan. Condition: **TRANS-4.** Operation: Adequate on-site parking is available for power plant personnel.		

TRAFFIC – GENERAL

The project site is located in the City of Blythe approximately five miles west of the downtown area, 0.25-mile north of Interstate 10 (I-10) within Riverside County in southeastern California. The entire BEP I/BEP II 152-acre site is to the north of and adjacent to Hobsonway, and to the west and adjacent to Buck Boulevard. Hobsonway serves as the I-10 frontage road in the area and as the business loop for the City of Blythe.

Three highways, Interstate 10 (I-10), State Route (SR) 78 (Neighbors Boulevard) and United States Highway 95 (U.S. 95, Intake Boulevard) provide regional access to the plant site. I-10 is a major four-lane divided, east-west freeway that links the Greater Los Angeles Metropolitan Region eastward through Phoenix and Tucson, Arizona to New Mexico and points east. U.S. 95 is a two-lane, north-south highway that provides access to the City of Blythe via the cities of Vidal and Needles. US-95 is located approximately 6.5 miles east of the BEP II site, and continues north through California into Nevada and on to Las Vegas. SR 78 is a two-lane, north-south highway that provides access to the Palo Verde Valley via the City of Brawley. SR-78 has its western terminus in San Diego County at Interstate 8, and is located approximately 1.5 miles east of the site.



From the west, site access is from the I-10/Mesa Drive interchange located near the airport and Hobsonway. From the east site access is via I-10 at interchanges located at SR-78, Lovekin Boulevard, or US-95, and then on Hobsonway to the site. (FSA, p. 4.10-4)

Congestion

The construction of the power plant causes additional trips by construction workers and delivery trucks to and from the site, increasing daily traffic volumes on the freeways and local streets. The potential impact of the project is measured by the LOS (Level of Service) of the surrounding roadway segment based upon average daily traffic volume. LOS is measured in a range from LOS A to LOS F. A LOS of A refers to little or no congestion, whereas LOS F is heavy congestion with significant delays and significantly reduced travel speeds. (FSA, p. 4.10-6)

Construction:

Commuting Workers

Construction of the generating plant facility would occur over an estimated 18 to 20-month period and would require a peak (three month) construction workforce of 387 workers, assuming a single shift and a 40-hour, five to six day work week. Construction workers commuting from the greater Blythe area would travel west on Hobsonway or travel west on I-10 to the I-10/SR 78 interchange and then on Hobsonway to the site; those workers who live west of the site would travel east on I-10 to the Mesa Drive interchange and then on Hobsonway to the site. Workers from both directions would enter the site from Buck Boulevard. Workforce vehicle trips were calculated based on this data.

The Applicant assumes an average automobile occupancy (AAO) of 1.1 persons per vehicle to represent a worst-case construction worker commute scenario. Using the AAO rate of 1.1 results in approximately 660 daily trips to and from the site with a maximum of 330 vehicle trips during the p.m. peak hour.

The AFC provides an analysis of projected year 2005 traffic conditions plus project construction traffic trips. An analysis of the peak hour forecast plus peak hour employee trips indicates that freeway segments in the area would continue to operate at LOS A. The AFC does not provide an analysis of the impact of project construction traffic on local roads. However, because the Palo Verde Valley Transportation Master Plan shows all local streets and intersections important to the project at LOS A for the near term (i.e., during the next 3-5 years), except for one intersection at LOS B (Eastbound I-10 exit/on-ramp), peak (three month) construction workforce of 387 workers. Thus, commuting workers will not create significant traffic congestion. (FSA, p. 4.10-9)

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. Project construction would add 25 trucks, or 50 trips, per day during the peak construction truck traffic month. An estimated 4,165 truck deliveries would be made to the plant site over the course of the construction period, for an average of 11 deliveries per construction working day.

Project construction trucks would follow the same routes as those used for BEP I. Access to the project site would be on I-10, SR-78 (Neighbors Boulevard), or US-95 (Intake Boulevard) to Hobsonway and then to Buck Boulevard, which is adjacent to the site. Project traffic may also access the site directly from Hobsonway. I-10 project truck traffic would access Hobsonway at Mesa Drive coming east and Lovekin Boulevard coming west. I-10, US-95, and Hobsonway presently incur a high level of truck traffic, whereas truck traffic on SR-78 is low. Most project construction truck traffic would use I-10 and US-95. I-10 truck traffic averages about 5,900 trucks per day, or about 39 percent of total traffic on I-10. Construction truck traffic from BEP II would not significantly alter the LOS values for I-10, SR-78, and US-95. In reviewing truck traffic on a monthly basis, overall highway impact of increased project construction traffic is not significant with the adoption of Condition **TRANS-5** to time and coordinate project traffic. (FSA, p. 4.10-10-11)

MITIGATION:

☑ The Project Owner shall prepare a Construction Traffic Control Plan to assure that construction does not create unacceptable congestion impacts. To achieve this goal, the

Project Owner will schedule arrival and departure times, minimize lane closures and use traffic control, and assure access to residences and businesses during construction. Condition: **TRANS-5**.

Power Plant Operation:
Operation of the generating plant would require a labor force of 20 full-time employees. A worst case scenario assumes that each employee would drive a separate vehicle to work and that they would make one round trip from home to work per day, generating approximately 40 vehicle trips per day. Adequate parking would be made available for employees on an on-site paved lot. The majority of the permanent workforce would reside in the greater Blythe area and their preferred route to work would be along I-10. BEP II operations-related traffic impacts are minimal, representing less than 0.1 percent of existing AADT on I-10. (FSA, p. 4.10-12)

The Applicant has estimated that there would be three truck round trips to the site daily, or 6 trips total, during plant operations. This addition to daily traffic will not significantly affect LOS levels. (FSA, p. 4.10-13)

MITIGATION:

☑ The Project Owner shall develop a construction worker parking and materials staging plan. Condition: **TRANS-4**.

Safety

Construction:
Deliveries would also include small quantities of hazardous materials, such as gasoline, diesel fuel, oils, solvents, cleaners, paints, etc., to be used during project construction. The Applicant has stated that the deliveries of hazardous materials to and from the site would be conducted in accordance with California Vehicle Code Section 31300 *et seq*. The Applicant expects less than two hazardous materials trips per day during the construction period.

The AFC does not select a specific truck route for supplying and removing hazardous materials, but notes that in accordance with the California Vehicle Code hazardous materials will be transported on state or interstate highways that offer the shortest overall transit time possible. The CHP has identified I-10, US-95, and SR-78 as roadways to be used in the transportation of designated hazardous materials. (FSA, p. 4.10-11) Construction will require the use of large vehicles, occasionally including oversize or overweight trucks.

The Palo Verde Unified School District bus route follows the routes that the project work force and construction trucks would take. However, school bus stops are at locations where there is sufficient room for buses to pull off the road, so there would be insignificant added risk to school bus occupants from project construction truck traffic. School locations are not on the project construction truck routes or the routes that the majority of the work force would follow. In addition, Hobsonway would be clear of heavy truck traffic by 5 AM so as not to interfere with school bus routes. (FSA, p. 4.10-11)

MITIGATION:

- ☑ Caltrans permits control vehicle size and weight. Condition: **TRANS-1**.
- ☑ California Highway Patrol and Caltrans permits control transport of hazardous substances. Condition: **TRANS-3**.
- ☑ Encroachment permits shall be obtained and construction-impacted roadways will be restored to their pre-construction condition. Condition: **TRANS-2** and **TRANS-7**.

Operation:

The Applicant has estimated that there would be three truck round trips to the site daily, or 6 trips total, during plant operations. This addition to daily traffic will not significantly affect LOS levels. The transportation and handling of hazardous substances associated with project operation can increase roadway hazard potential. Impacts associated with hazardous material transport to the facility can be mitigated to a level of insignificance by compliance with existing federal and State standards established to regulate the transportation of Hazardous Substances. (Condition **TRANS-3**)

The California Department of Motor Vehicles specifically 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 that is available for review 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. The Applicant has indicated that the transportation of hazardous materials to and from the site would be conducted in accordance with all applicable LORS for the handling and transportation of hazardous materials. (FSA, p. 4.10.13)

The handling and disposal of hazardous wastes is addressed in the **WASTE MANAGEMENT** section.

MITIGATION:

- ☑ Hazardous materials haulers must be specially licensed by the California Highway Patrol. Condition: **TRANS–2** (See also **HAZARDOUS MATERIALS** section.)

Aviation Safety – Blythe Airport

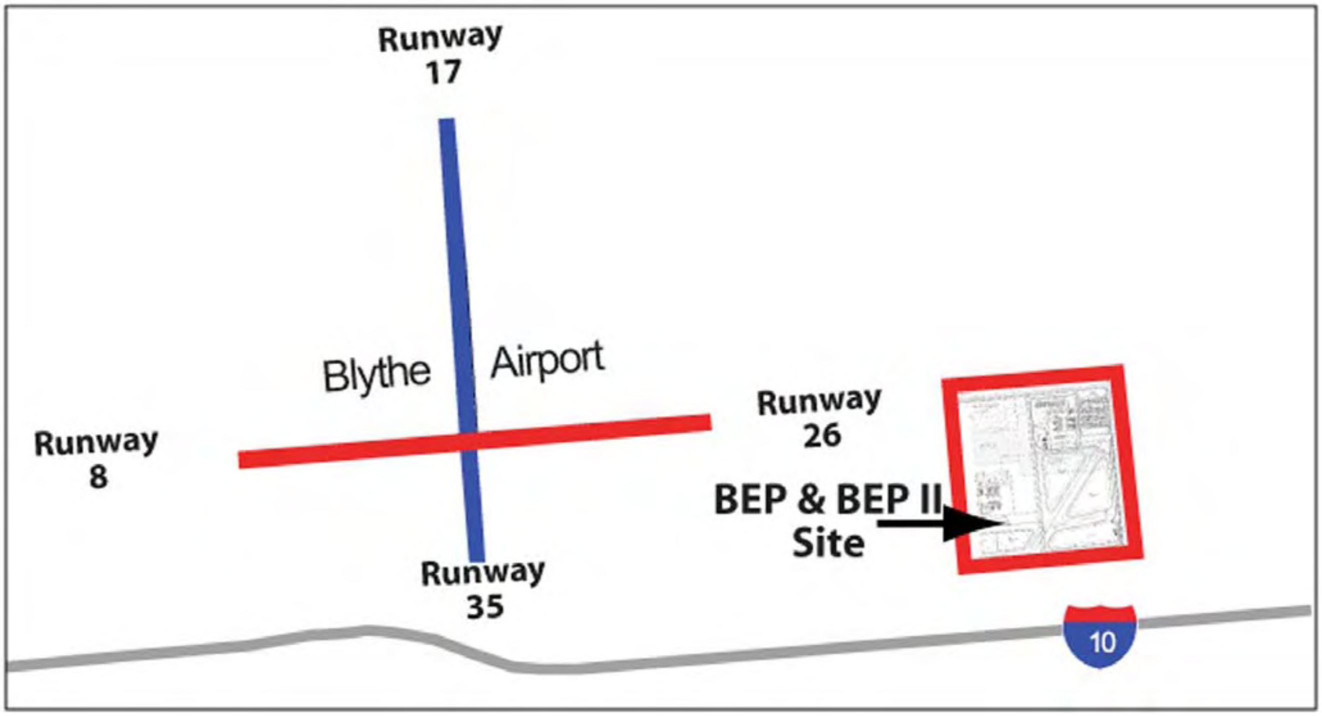
By its March 21, 2001, Decision, the Energy Commission authorized the construction and operation of the Blythe I (BEP I) power plant at its current location. The Decision stated the following regarding airport operations (pages 256 & 257):

> Aircraft landing from the east at Blythe Airport may fly over the project site on approach. The east edge of the primary airport runway (Runway 8-26) is approximately one mile

> west of the BEP site. The end of Runway 8-26 is located at 393 feet above mean sea level (MSL). The BEP is approximately 335 feet above MSL. When constructed, the power plant heat recovery steam generator stacks will be 130 feet high. The stacks are estimated to be 72 feet above the level of the runway. When using the lowest Instrument Landing System (ILS) angle (2.9 degrees) for Runway 8-26, the height of the aircraft during landing approach over the stacks could be about 168 feet.
>
> The Federal Aviation Administration (FAA) has made an evaluation related to the project stack height and found that the proposed structure would not exceed obstruction standards and would not be a hazard to navigation. Based upon this evaluation, marking and lighting are not necessary of aviation safety. The FAA did indicate, however, that if marking or lighting were accomplished on a voluntary basis that it be installed and maintained in accordance with FAA requirements. The applicant will install lighting on the power plant stacks in accordance with FAA requirements. The ILS approach to Runway 8-26 has not been approved by the FAA.
>
> The BEP will have two evaporation ponds with a combined surface area of approximately 16 acres. These ponds may attract birds that could adversely affect aircraft during landing from or departing to the east. In addition, the proposed project may generate visible cooling tower plumes of various sizes during certain times of the year. The Riverside County Airport Land Use Commission (ALUC) found BEP was consistent with the Blythe Airport Comprehensive Land Use Plan subject to a number of conditions. One of the conditions requires BEP to submit prior to any permit an avigation easement to the County of Riverside which will insure that the project does not adversely affect Blythe Airport operations. We have included a condition of certification to require proof of the easement.
>
> Caltrans Aeronautics reviewed the project and initially raised some concerns about potential adverse impacts related to airport operations that included the effects of heat and visible plumes, electrical interference, and approaches to runway 08/26 from the east. However, after further correspondence with the City of Blythe and the acknowledgement that the runway would not be extended to the east, Caltrans has determined that its concerns have been adequately addressed.

The Blythe Airport is located approximately one mile west of the proposed BEP II site off of Hobsonway. The airport is outside the current boundary of the City of Blythe and is located in unincorporated Riverside County. The airport property includes the planned Blythe Airport Industrial Park area. Blythe Airport is owned by Riverside County, which contracts with the City of Blythe for operations.

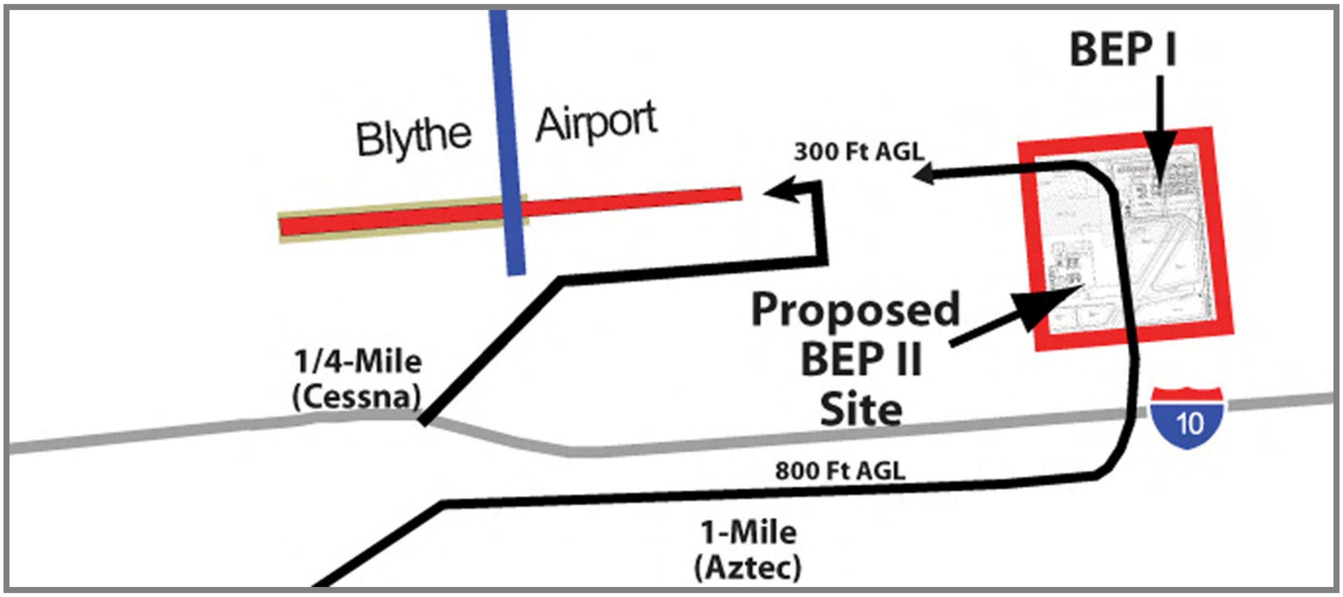
There are two operating runways at Blythe Airport. Runway 8-26 (oriented east-west) is the primary runway and is 6,562 feet long, and 150 feet wide. Runway 17-35 (oriented north-south) is 5,820 feet long and 100 feet wide. Runways are designed for aircraft to land in either direction. Aircraft landing to the west at Blythe Airport would use Runway 26, which is 260 degrees on the compass. Likewise, aircraft landing in the opposite direction would use Runway 8, which is 80 degrees on the compass. Runway 17-35 refers to its landing directions of 170 degrees and 350 degrees, respectively. The Blythe Airport runways are 393 feet above mean sea level (MSL).



The airport can accommodate business jets and transport type aircraft, as well as smaller training aircraft. Flight training companies frequently use this airport. Activity at the airport consists of an average of 67 aircraft operations per day. Runway 8-26 is the main runway, with 75 percent of Blythe Airport air traffic landing toward the west on Runway 26. (FSA, p. 4.10-5, 15)

Several factors affect air traffic patterns at an airport. The primary factor is whether a pilot is operating under Visual Flight Rules (VFR) or Instrument Flight Rules (IFR). A VFR-rated pilot cannot fly in clouds or fog and must have prescribed minimum visibility. So, a VFR-rated pilot must be able to see a runway for landing and avoid other aircraft in flight or obstacles on the ground. IFR procedures are required when weather conditions do not satisfy VFR requirements, but only instrument rated pilots may fly under IFR conditions. A pilot flying under IFR conditions must be able to see the runway at a prescribed Minimum Descent Altitude in order to execute a landing. The Blythe Airport operates primarily under VFR, although it has a very high frequency omni-directional range (VOR) instrument approach, and an Instrument Landing System (ILS) approach for practice instrument approaches. The ILS is not certified by the FAA and is for training purposes only. (FSA, p. 4.10-15)

FAA guidelines establish the standard traffic pattern used by pilots under VFR conditions. Standard airplane traffic patterns consist of a generalized routing using three legs of a rectangular path leading to the runway and beginning at an altitude of 800 to 1,000 feet above the airport elevation for small planes. The Blythe Airport uses a standard left-hand traffic pattern entered at an altitude of 800 feet above ground level (AGL) for the downwind leg, and 300 feet AGL for final approach. However, at airports without an air traffic control tower, such as the Blythe airport, pilots can choose to make a straight in approach, as opposed to flying the standard pattern.



The Blythe Airport supports a Unicom radio frequency, attended by the Fixed Base Operator, which allows a pilot to state his/her position and landing or departure intentions, obtain airport, altimeter and wind information, and communicate with other aircraft operating in the airport environment.

When entering a traffic pattern for landing, the normal procedure for pilots of average single-engine planes is to broadcast his/her position and intention on the Unicom frequency and then enter the downwind leg parallel to, but between ¼- to one-mile away from, the runway. As a general rule, lighter aircraft (Cessna) fly slower in the pattern than heavier single and twin-engine aircraft which generally need to fly faster to maintain needed lift. Thus, lighter aircraft usually use a “tighter” pattern, closer to the runway for the downwind, base and final legs of the pattern. Heavier or faster aircraft will use longer pattern legs. For takeoffs, the normal procedure is to fly straight ahead until reaching an altitude of at least 400 feet above the airport before making a climbing left turn to stay in the traffic pattern, or continuing to climb and go straight or turn to proceed to another destination. Likewise, a departing pilot would broadcast the intended departure route before take-off.

In taking-off from the Airport using Runway 26, pilots head west, away from BEP I. Depending upon their destination, they may continue west or turn to proceed in any direction. If a pilot were practicing take-offs and landings (touch & go’s), the pilot would make a series of left turns to line up for the final approach to Runway 26. Depending on aircraft size and speed, this pattern *could* (at the pilot’s discretion) take the aircraft over BEP II and/or BEP I at approximately 300-500 feet above ground. The centerline of runway 26 extends through the middle of BEP I. (FSA, p. 4.10-16)

Since BEP I began operating, Energy Commission staff has received five documented complaints from pilots regarding moderate to severe turbulence encountered when flying over BEP I while attempting to land on runway 26. One of the complainants is Intervenor Pat Wolfe who is the Fixed Base Operator at the Blythe Airport and an experienced pilot.

Another complainant is Joseph Sheble, father of Intervenor Wolfe's expert witness at the evidentiary hearings. Both of these complainants were flying single engine Cessnas.

The pilots encountered the moderate to severe turbulence when flying at altitudes ranging from 300 to 1,000 feet above ground level in weather conditions that were clear, calm, and relatively cool. Most of the flights were in the morning, and both single and two engine planes were involved. Four of the five complainants were experienced pilots who were sufficiently concerned about the turbulence to notify the airport operator. (FSA, p. 4.10-17)

After receiving these complaints, Staff sought to further investigate the potential severity of the turbulence and its implications for impacts resulting from BEP II. Energy Commission staff's aviation safety expert, Bill Arnold, an experienced pilot, flew over BEP I on three separate occasions. During these flights, he experienced moderate turbulence in a twin-engine airplane (Aztec) at approximately 500 feet above ground. There was no warning to the pilot that he was about to experience turbulence. Regarding this flight, Mr. Arnold stated, "If I had been flying a lighter single-engine aircraft the turbulence would likely have been severe." (FSA, p. 4.10-17)

In Staff's analysis, the creation of turbulence from BEP I is of particular concern because aircraft flying over BEP I are preparing to land on Runway 26 and are relatively close to the ground (typically 300-500 feet above ground level) and traveling relatively slowly (75 to 90 miles per hour). Under worst-case conditions (solo pilot, small plane, flying at or below approach altitude, cool winter night or early morning with little or no wind, power plant at full load), unexpected severe turbulence can cause sudden and significant aircraft position changes (such as 90 degree rolls to the left or right). High angle turns at low speed will result in a loss of aircraft lift and altitude. In addition, sudden aircraft position changes at night can result in pilot vertigo – the loss of reference to the earth's horizon. This can result in pilots' losing their sense of what is up and what is down. At night, this can easily lead to an aircraft accident. This problem is exacerbated if the pilot is inexperienced or the aircraft is experiencing emergency conditions. (FSA, p. 4.10-17)

The Applicant's expert pilots also flew through the BEP I plumes in a similar twin-engine aircraft and reported that the turbulence was at most moderate and the aircraft was controllable using ordinary pilot skills. (Morris, pp. 2 & 3)

Thermal Plumes

To better understand the potential turbulence from thermal plumes (both when visible or not visible) generated by BEP I and potentially by BEP II, Staff modeled the plumes generated by both the cooling towers and the HRSGs.

The factors involved in creating significant ***non-visible*** plumes include calm wind speed conditions of less than five knots (knot = 1.15 mph) coupled with an ambient temperature below 70 degrees Fahrenheit. These conditions occur approximately 550 hours per year (based on three years of Blythe Airport meteorological data). Plume turbulence may also occur during low wind speeds that are somewhat greater than five knots, but the worst turbulence will occur when winds are dead calm.

Significant ***visible*** plumes that would be high enough to obstruct air traffic would only be formed under calm conditions where the ambient temperature is fairly low (40 degrees) and relative humidity is fairly high. Conditions conducive to creating visible plumes that may extend vertically 500 feet or more occur approximately 50 to 150 hours per year (based on modeling results). The conditions conducive for turbulence and visible plume occurrence overlap and both occur almost exclusively from October through May with the vast majority occurring during the overnight and morning hours (10 p.m. to 10 a.m.).

The BEP II cooling tower is proposed to contain eight cells, each 40 feet tall and 33 feet in diameter. The entire cooling tower structure will be 472 feet long. The cooling tower exhaust temperature will range from approximately 60 to 95 degrees Fahrenheit, depending upon ambient conditions. During low ambient temperature, the maximum difference between the temperature of the exhaust and the receiving ambient air is likely to be 35 to 40 degrees.

The velocity of the cooling tower exhaust is designed to be 8.5 meters per second (1,670 feet per minute or 19 miles per hour). The exhaust temperature from the HRSGs would be around 200 degrees Fahrenheit, and the velocity is designed to be approximately 20 meters per second (3,900 feet per minute or 45 miles per hour) when operating at full load.

Based on its modeling results, Staff estimates that the thermal plumes generated by the cooling tower would easily exceed 500 feet above the ground. At this height, under calm cool conditions, the average velocity of the plume would likely be greater than 4.3 meters per second; and at 250 feet above the ground, considering the thermal buoyancy, the plume would have an average plume velocity of almost double that at 8.5 meters per second or greater depending on ambient temperature. (FSA, 4.10-18)

Similarly, Staff estimates that the thermal plumes generated by the HRSGs would also easily exceed 500 feet above the ground. The average velocity of the HRSG exhaust in calm conditions, neglecting the additional thermal forces, is estimated to be approximately 10 meters per second at 250 feet above the ground. The plumes from the HRSGs are more widely spaced and narrower and would not merge in the same way as the eight adjacent cooling tower cell exhaust plumes; the overall size of the plume, if encountered by an aircraft, would be much smaller than the cooling tower plume and the impact would only be felt momentarily. Thus, the cooling tower is the greater concern for hazardous turbulence. (FSA, p. 4.10-18)

Likewise, the Applicant modeled potential plumes and determined that, at the point of potential intersection of a plume and landing aircraft, the plume's temperature is almost ambient and the upward velocity is estimated to be 5 feet per second for the cooling tower and 7 feet per second for the HRSG stack. The upward velocity of the project plumes is similar to natural thermal turbulence that occurs with rapid summer ground heating. (Kosky Report, pp. 2 & 3)

Commission Discussion
With regard to plume velocity and its turbulence-creating effect, the Staff and Applicant contested each other's methodologies and results. The Commission need not resolve which expert is correct, or even more correct. Both parties used dispersion models that were not designed to evaluate the turbulence effect of plume updraft from either the HRSG exhaust stack or the cooling towers. In fact, the dispersion models are not geared for a calm wind condition, which all parties agree represents the worst-case for aircraft encountering thermal plume-generated turbulence.

The Commission finds that it is sufficient to say that encounters with the project's thermal plumes can adversely affect aircraft operations. All test flights of both the Staff and Applicant over BEP I plumes encountered turbulence. The plume from the cooling tower is the greater potential hazard due to the size of the cooling tower and the initial temperature and velocity of the plume. The evidentiary record is unequivocal that the plume impact is potentially most adverse during cool (40-degree range) and calm conditions, because of the plume's differential with the ambient temperature and the absence of mixing that would occur with wind. Temperature and wind records, not modeling, show these conditions can occur from October to May, mostly during overnight and early morning hours. The Commission also notes that under these conditions the thermal plumes are usually visible.

Moreover, when there are sufficiently strong winds from the west so that aircraft must land on runway 26, the thermal plumes are effectively dispersed and cause no material effect on aircraft operations. (8/2 RT 22:21-23:4)

Impact Upon Aircraft

Energy Commission Staff
As stated previously, BEP II non-visible and visible thermal plumes would be substantially similar to BEP I plumes. Aircraft contacting the BEP II thermal plume on approach to Runway 26 could be affected in a similar manner to that described previously for the BEP I thermal plume. While the BEP I and BEP II plumes will not merge to create a single, area of turbulence, Staff believes that the combined effect of having two turbulence-causing plumes in close proximity, within one mile of the Blythe Airport, on and near the extended runway centerline for Runway 8-26, would have a potentially significant adverse impact on aircraft safety. Aircraft on approach to Runway 26, depending on weather and power plant operating conditions, could experience turbulence from either or both of the BEP I and BEP II cooling towers and/or HRSG stacks. (FSA, pp. 4.10-18-19)

Visible plumes from the BEP II cooling tower, although not expected to occur many hours during the year, still present a hazard to aircraft on final approach to Runway 26 by temporarily obscuring the pilot's view of the airfield, runway and airspace where other aircraft may be operating. For safety reasons, pilots will normally avoid flying through visible plumes that can reduce or eliminate visibility, and particularly when the plume blocks the view of Runway 26. Since plume form and angle may change due to variable factors such as wind direction and wind speed at different altitudes, Staff believes plume avoidance may not always be a possible when trying to maintain a glide path (descent) for a safe final approach.

On final approach, pilots, besides looking outside for other aircraft and to see where they are going, also need to perform a variety of tasks such as frequently checking the aircraft instruments to ensure proper engine operation, maintaining a standard rate of descent (approximately 500 feet per minute), and possibly communicating by radio with other aircraft in the traffic pattern. Some aircraft may also have retractable landing gear that requires putting the landing gear down during the preparation for landing procedures. Twin-engine planes have additional complications in their landing procedures that also require the pilot's attention. Student pilots in particular, and many pilots in general, use written checklists during landing to ensure they do everything required for a safe landing. All of these activities demand the pilot's attention starting at a certain point on the downwind leg of the traffic pattern, or several miles away for straight-in approaches, until and after touchdown on the runway. (FSA, pp. 4.10-19)

Staff also presented an Advisory Circular (AC 139-05; June 2004) from the Australian Civil Aviation Safety Authority (CASA), entitled *Guidelines of Conduction Plume Rise Assessment* that provides guidance to airport operators and operators of facilities with exhaust plumes and information required to assess potential hazards from plumes. The Circular observes that the "stability of an aircraft is especially critical during periods of high pilot workload, such as when the aircraft is being maneuvered at low altitudes with flaps extended and/or gear down." (§ 2.3) CASA requires the proponent of a facility with an exhaust plume, which has an average vertical velocity exceeding the limiting value (4.3 m/s at 360 feet AGL) to be assessed for the potential hazard to aircraft operations. (§ 4.6)

Applicant

Applicant witnesses acknowledge that aircraft flying a left-hand pattern for landing on runway 26 could fly over the thermal plumes of the project's cooling towers. However, if the VFR pattern to runway 26 were converted to right-hand turns, then air traffic would be repositioned from the south to the north side of the runway and avoid overflight of the project. The City of Blythe has called for the pattern change in its "override" Resolution 04-897. The Applicant has agreed to seek FAA approval of such a change. The traffic pattern change would also avoid overflight of the residential area (Mesa Verde) south of the airport.

However, if aircraft did overfly the project's cooling towers at pattern altitude in calm winds, the Applicant's witness believes that a pilot would experience up to moderate turbulence. The Applicant's expert witness conducted test flights over the BEP I facility in a twin-engine Piper Aztec at various altitudes to evaluate the impact of the thermal plumes.

The updraft from the plume would cause a gain in altitude and speed, rather than a dangerous decrease in altitude. At low approach speeds, the plume turbulence will not cause structural damage to the airframe. Moreover, plume turbulence is similar in magnitude and short duration to thermals encountered in normal summer desert flying. Lastly, for an inexperienced pilot startled by the plume turbulence, the inherent stability of an airplane prevents a hazardous condition from occurring. Only inappropriate pilot behavior reacting to the plume turbulence would make the encounter hazardous. (Morris, pp. 1 & 2)

Intervenor
Mr. Wolfe, the Fixed Base Operator at the Blythe Airport, testified that the ILS is an asset to the Airport, even though it is not FAA certified, for training to fly under instrument meteorological conditions. As the Fixed Base Operator, Mr. Wolfe controls the Blythe Airport's Unicom radio frequency. Mr. Wolfe testified that solution to the BEP I plume problem is to notify pilots on "a certain frequency," but as the license-holder of the Unicom frequency, he does not currently notify pilots regarding BEP I on that frequency. He offered to do so for compensation. (8/2/05 RT 160:20 – 163:19)

Mr. Wolfe also presented an expert witness (Joseph Sheble, an FAA accident prevention and safety counselor and flight instructor) who testified that the project plume updraft should be considered "wind shear." Student pilots use the Blythe Airport as their "long cross-country" flight. Students do not react from instinct or experience, and so would not have sufficient time to figure out what to do if the aircraft began to stall from the plume while only 350-feet above ground.

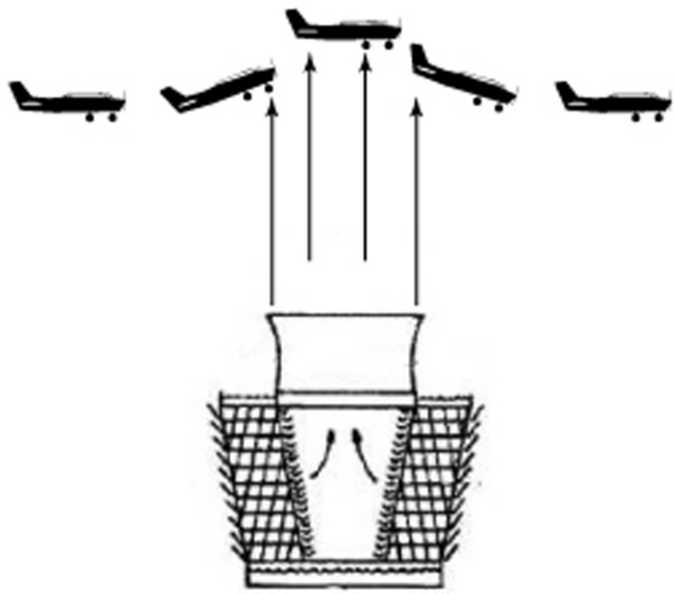
Mr. Sheble also testified that his employee, also a flight instructor, entered the BEP I cooling tower updraft with only one wing, causing his aircraft to roll to 40-50 degrees, which is a very dangerous configuration at 550-feet off the ground.

Currently, about half the aircraft landing on runway 26 turn from downwind to base leg between the end of the runway and the BEP I facility. If BEP II were built, the length of the downwind leg would be reduced (by approximately 800-feet), thus allowing only the slow aircraft to turn to the base leg "inside" the project. Faster aircraft would go around BEP II, but encounter BEP I during the "final" leg of the pattern down the centerline of the runway. As pilots have become aware of the plume updraft, they maneuver around the plume. The concern is pilots who are using the Airport for the first time and have no knowledge of the plumes.

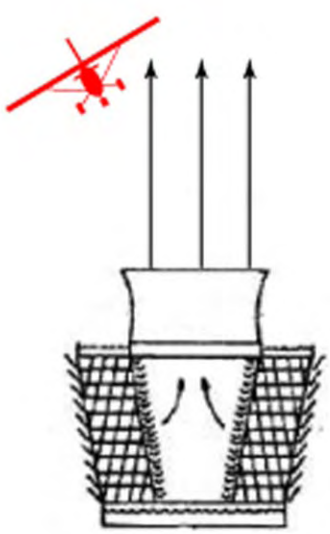
Mr. Sheble then testified that a real and extreme danger would be created if the pattern were changed to right turns by causing the turn from base to final leg to be over the cooling towers. Additionally, the pilot's visibility is obscured from the outside of a turn for low-wing aircraft, and to a lesser extent high-wing aircraft. Crossing over the cooling towers while in a banked turn would create a dangerous condition. Lastly, Blythe Airport area pilots are used to the left-hand pattern, so a change to a right-hand pattern could cause two aircraft to hit head-on while turning base to final leg for runway 26. (Sheble, pp. 3-5; 8/2 RT 150:14 – 160:7)

Commission Discussion
The Commission review of the potential effects upon an aircraft from encounter with the project's thermal plume shows two possible scenarios. Flying through the plume will cause the updraft to initially act upon the nose and wings, causing the aircraft to pitch upward. As the aircraft continues to move forward, the updraft will then act upon the tail, causing the tail to rise and essentially leveling the aircraft and avoiding a stall. This is part of the inherent stability of the aircraft referred to in the testimony. As the aircraft continues to move forward, the nose and wings will leave the updraft, causing the aircraft to pitch downward. Lastly, continuing upward lift on the tail would cease as the aircraft exited the plume.

If forward speed were lost during the initial pitch-up entering the plume, that speed would be regained by the pitch-down exiting the plume. This is another element of the inherent stability of the aircraft, since gravity causes acceleration in a nose-down attitude, which in turn creates lift stopping any net lost of altitude. *Without any pilot input to the controls*, the aircraft should gain a bit of altitude as it transits the plume. In lay terms, flying through a thermal plume is like flying over a "speed bump" in the air, as shown graphically below.



By contrast, the potentially more problematic encounter with the thermal plumes of the project's 8-cell cooling tower is flying along its axis, which will cause the aircraft to roll. Roll results from the updraft of the plumes operating on only the wing and tail of one side of the aircraft. The roll effect will begin as soon as the wing surface encounters the plume updraft. If the fuselage (center of gravity) does not also enter the updraft of the plume, the aircraft will not gain any altitude.



Instead, the roll will induce an uncoordinated, slip-turn away from the plume. (A "proper" coordinated turn is induced by the pilot's application of ailerons and rudder.) With sufficient time and distance, the inherent stability of the aircraft, with equalized pressure under all wing and tail surfaces, would return the aircraft to straight and level flight. However, pattern altitude is insufficient to assure the safe recovery of aircraft *without immediate, appropriate pilot input to the controls to stop the roll*.

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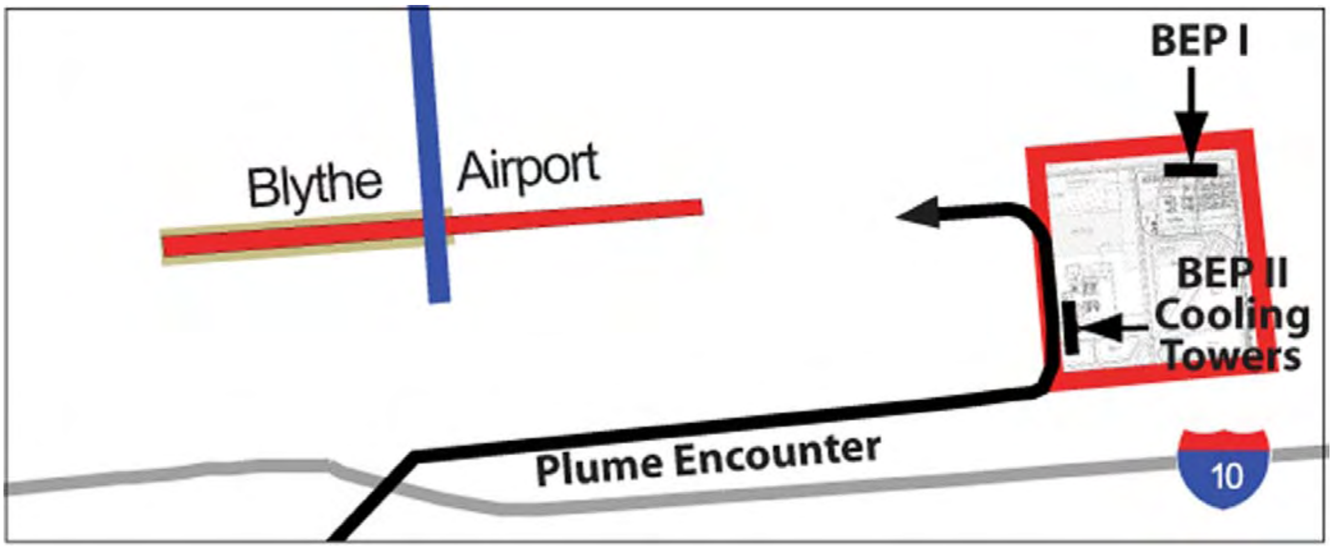
For BEP II, this roll scenario would be encountered in a VFR left-hand pattern as the aircraft is on the “base” leg, proceeding parallel to the cooling towers. Encountering the thermal plume while in a deliberate banked turn, transitioning from the downwind to the base leg, could be more problematic. However, standard piloting procedures would recover the aircraft to safe flight.



The Applicant suggested that the turbulence encountered in the plume is virtually the same as natural turbulence encountered in summer desert flying. Staff counters that an encounter with a thermal plumes is an unexpected and startling event which is unsafe because it occurs close to the ground; encounters with natural turbulence is more predictable and usually occurs at higher altitude. The Commission need not choose from the parties' positions for both are correct. Generally, turbulence is turbulence, so that in the thermal plume an aircraft could bump and jolt about the same as it would in natural turbulence. Moreover, with the application of ordinary piloting skills, an aircraft can safely pass through turbulence. However, encountering the turbulence of a non-visible thermal plume while in the Airport traffic pattern would be an unexpected and startling event, requiring recovery of the aircraft with little available altitude to do so.

The Commission finds that the project's thermal plumes could significantly upset flight in the left-hand pattern for runway 26. A visible plume, while representing the worst-case turbulence scenario due to difference in plume and receiving air temperatures, also presents a pilot with a visual warning to avoid the plume. The non-visible plume provides no such warning.

The Commission believes that a well-trained pilot can recover the aircraft from plume turbulence using ordinary piloting skills. The Commission recognizes that there is an inherent stability in the design of an aircraft that also aids recovery of the aircraft penetrating plume turbulence. However, the Commission finds that aircraft roll induced by flying along the axis of the project's cooling tower (which could occur on base leg) represents a sufficient hazard, particularly to inexperienced pilots, to warrant appropriate mitigation.

Proposed Mitigation

<u>*Energy Commission Staff*</u>

On March 18, 2004, Staff sent a letter to the Aeronautics Division of the California Department of Transportation (Caltrans Aeronautics) seeking recommendations for reducing the adverse impact caused by BEP l. Staff also contacted the FAA with a similar letter sent on May 20, 2004. Caltrans responded in a letter dated March 24, 2004, with several suggestions including:

1. Adding a remark to the Airport Facility Directory advising pilots to avoid low-altitude direct overflight of the BEP l power plant;
2. Adding a similar remark to the Airport Surface Observing System (ASOS); and
3. Installing a new Instrument Landing System (ILS) on Runway 17 and deactivating the ILS on Runway 8-26.

Before flying to a particular destination, pilots consult the Airport Facility Directory (AFD) to obtain information on specific airports. The AFD contains, among other things, information about hazards surrounding the airport. Based on a Staff request, on July 10, 2004, the FAA added a remark to the AFD for the Blythe airport notifying pilots about the potential for turbulence above BEP I and advising that over-flight of the power plant should be avoided.

The ASOS is a radio announcement generated at each airport containing important information specific to that airport such as weather and flying conditions. Most pilots tune to the frequency (not on the Unicom frequency) so that they receive this information as they approach the airport. Staff has also requested that the FAA add an announcement to the Blythe Airport ASOS alerting pilots to potential turbulence above BEP I and advising avoidance of the plant.

The ILS allows pilots to approach the airport for landing using only the plane's instruments. The IFR-rated pilot who does not have any visual references inflight or on approach, must acquire sight of the runway at the Minimum Descent Altitude, which is 400-feet AGL at the Blythe Airport, in order to land. The ILS at the Blythe Airport is used for training and calibration purposes only.

In Staff's view, the problem with the ILS being located on Runway 8-26 is that it requires pilots using it to fly over BEP l. This can bring the pilots, who are flying on instruments, directly through the thermal plumes. It is staff's understanding that the majority of ILS approaches are flown by aircraft with two pilots. However, given the invisible nature of the thermal plume, the presence of an additional pilot is not an advantage. Were the ILS moved to Runway 17-35, pilots using the ILS would no longer be required to fly low over BEP I, and approximately one-third of the landings would be entirely shifted to this second runway. Staff is currently working with Caltrans Aeronautics, the FAA, the Blythe Airport Manager, and the BEP l owner to implement the movement of the ILS in a compliance proceeding for BEP I. (FSA, p. 4.10-21)

The only possible mitigating change to the project that Staff could find was installing fans to reduce or eliminate the HRSG and cooling tower plumes. Upon further analysis of this option, Staff determined that it would not sufficiently disperse the cooling tower plumes to reduce the impact of the plumes to less than significant. (FSA, p. 4.10-23)

With regard to changing the traffic pattern for Blythe Airport Runway 8-26 **(**and also Runway 17-35) from the current left hand flow to a right hand flow, Staff stated that this change would substantially reduce the number of aircraft flying over the BEP II project, but would have no effect on approach over-flights from the south, southeast and east. The BEP II visible plumes would also be a potential hazard to aircraft in the traffic pattern, on straight-in approaches, and on final approach when winds of sufficient speed from the south push the plumes to the north. (FSA, p. 4.10-23) Thus, in its April 2005 FSA, Staff concurred with the CalTrans Aeronautics' conclusion, at the time, that it was inappropriate to build another power plant near Blythe Airport. (FSA, p. 4.10-24)

<u>Staff – BEP I Compliance Proceedings</u>

Following receipt of the pilot plume turbulence complaints, Staff began informal exchanges with Florida Power and Light (FPL), the owner and operator of BEP I. Following stakeholder meetings in late 2004, the Staff facilitated some corrective measures, notably establishing an FAA Notice to Airmen (NOTAM) and a warning in the FAA Airport Flight Directory. In a May 17, 2005, letter to FPL, the Energy Commission's Deputy Executive Director acknowledged that these corrective measures "helped to significantly reduce any safety concerns." However, the Executive Director stated that prudence required that *all* reasonable measures be taken to avoid impacting aircraft using the Blythe Airport. The Executive Director advised FPL that, if FPL did not commit to funding a new ILS on other than runway 26, the Staff would file a complaint at the Commission.

On July 19, 2005, Staff facilitated a meeting of representatives from FPL, the City of Blythe, Caltrans Aeronautics, the FAA, and staff's aviation consultants, which resulted in agreement on additional corrective measures and assigning their implementation. FPL agreed to pursue appending a message on the existing Airport Surface Observation System (ASOS) broadcast warning pilots of the thermal plumes and further agreed to work with the City of Blythe to change the airport's traffic patterns from left-hand to right-hand, to limit ILS usage to periods of wind speeds greater than five knots, and to designate a different calm wind runway. These agreements were recited in an August 30, 2005 letter to FPL from the Energy Commission's Executive Director. However, the Executive Director expressed concern over the amount of time to resolve the flight safety issue and advised FPL that the Staff would file a complaint with the Commission if the following were not implemented by October 28, 2005:

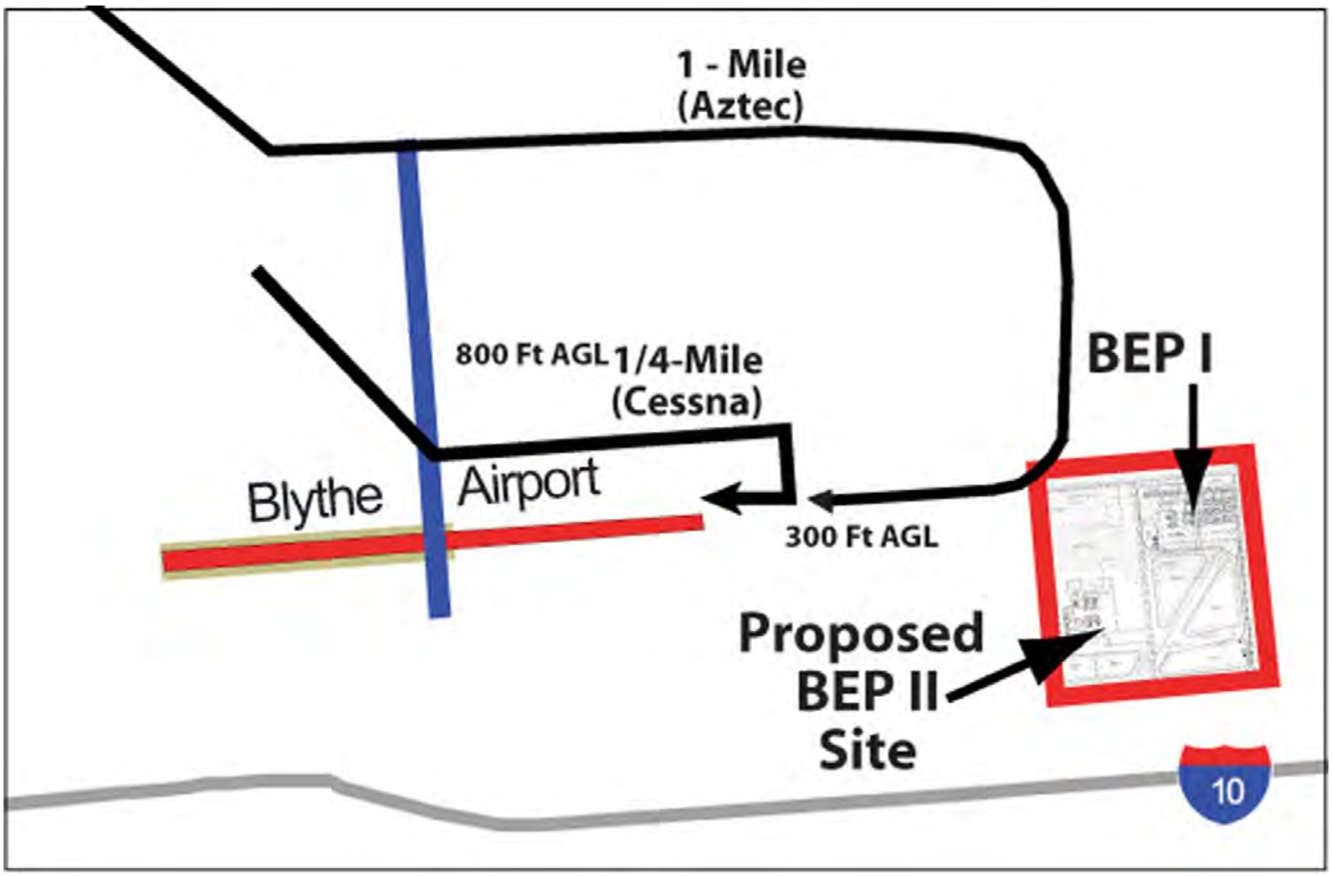
1. Decommissioning the existing ILS on runway 26;
2. Changing the airport's traffic pattern from left-hand to right-hand;
3. Appending a thermal plume avoidance advisory to the existing ASOS; and
4. Designating a different calm wind runway.

As of the completion of this Presiding Member's Proposed Decision, no complaint had been filed or other proceedings initiated.

Applicant
The BEP II Applicant, in apparent coordination with the BEP I project owners, agrees to a Condition of Certification which would require facilitating the following changes to Blythe Airport operations:

1. Request the FAA to add a remark to the Airport's Automated Surface Observation System (ASOS) advising pilots to avoid low-altitude direct overflight of the power plant;
2. Modify the VFR traffic pattern to runway 26 from left-hand turns to right-hand turns, thereby repositioning the pattern from south to north of the Airport; and
3. Designate other than runway 26 as the primary calm wind runway.

The City of Blythe adopted its Resolution 04-897, overriding the negative advisory vote of the Riverside County Airport Land Use Commission on siting the BEP II project one mile east of the Airport. The Resolution contained multiple conditions, including changing to a right-hand traffic pattern and adding the advisory to the ASOS.



Caltrans Aeronautics Staff

Energy Commission staff has worked closely with Caltrans Aeronautics staff. In a letter dated March 12, 2005, Caltrans confirmed that it remains "…committed to our position that the establishment of an additional power plant (i.e.. BEP ll) in the nearby proximity to the end of Blythe's Runway 8-26 is not conducive to promoting a safe operational flight environment. We see no need to exacerbate an already questionable situation that does not enhance aviation safety. It remains our position that we do not recommend construction of a power plant facility at the proposed location." (FSA, p. 4.10-23)

At the evidentiary hearing, the Caltrans representative stated the following:

> My safety concerns are to improve the situation that exists [with BEP I] and totally won't go away in the first place. So, yeah, if I was notified by the City [of Blythe] that the FAA had approved right-hand traffic to [runway] 26, and preferential [primary calm wind] runway 8, and the notice in the ASOS or AWOS or some other communication system was in place, the notice in the AFD that picked up by pilot guides stays in place, yeah, I'd say we'd accomplished as much as we might accomplish under the circumstances. (8/2/05 RT 137:1-10)

When asked whether he would be more "comfortable" with a certification for the project with the Applicant's-agreed conditions, the Caltrans representative stated:

> Comfortable, yeah, comfortable. … I mean we're at a point now where we're just trying to get the best we can out of a situation that came up because we just didn't know at the time with Blythe I. … So I'm saying, yeah, I would be more comfortable.

Presiding Commissioner Geesman noted that the Caltrans testimony was not consistent with a March 12, 2005 Caltrans letter and requested that Caltrans' position be provided in writing for our record. (8/2/05 RT 138:1 – 140:7) The Energy Commission staff states that the Commission should not rely too greatly on Caltrans' apparent change in position. (Staff Opening Brief, p. 2)

Commission Discussion

The aviation safety issues arising from BEP I and the potential issues arising from BEP II are distinct. The BEP I cooling towers are virtually along the extended centerline of runway 26; the BEP II cooling towers in the left-downwind or left-base pattern for landing on runway 26.

Blythe I has been "officially" operating since December 29, 2003, according to Energy Commission records. Of the approximate 580 days between beginning BEP I operation and the evidentiary hearings (August 1, 2005), the power plant has operated 271 days. Staff testified that the Blythe Airport experiences an average of 67 flight operations per day, which includes take-offs and landings. (FSA, p. 4.10-15) Therefore, based upon these averages, there have been approximately 39,000 flight operations at the Airport since Blythe I began operating. Approximately half of those operations, 19,500, were by student pilots.

If the Commission were to assume that half of the total flight operations since BEP I began operation were landings and 75-percent of landings were on runway 26 per Staff's testimony, then the incidents reported represent .07 percent of all runway 26 landings, and .15 percent of student pilot landings on runway 26. The flight operation statistics suggest that pilots using the Blythe Airport have adapted to the presence of BEP I.

For purposes of this Decision, the Commission will adopt as a condition the agreements reached by the Blythe Airport stakeholders, and specifically the Applicant, to mitigate the potential flight risk we identified, namely induced roll while flying along the cooling tower axis on the left-base leg for inexperienced pilots.

Therefore, the Project Owner shall not commence construction of BEP II until the following are accomplished:

1. A remark is placed on the Airport's Automated Surface Observation System (ASOS), or equivalent broadcast, advising pilots to avoid low-altitude direct overflight of the power plant;
2. The VFR traffic pattern to runway 26 is changed from left-hand turns to right-hand turns; and
3. A runway, other than runway 26, is designated as the primary calm wind runway.

The change to a right-hand pattern removes BEP II entirely from the landing pattern to runway 26 and adds approximately 800 feet from the end of runway 26 to the cooling towers of BEP I compared to the cooling towers of BEP II. Effectively, therefore, the downwind leg of a right-hand pattern could be 800 feet longer than a left-hand pattern.

Although having mixed approach patterns is not unusual, having the three other approaches to landing remain left-hand patterns, with one right-hand pattern for runway 26, is not a panacea. To some degree this mitigation merely substitutes risks. On the one hand, there is a risk to pilots encountering the thermal plumes from a large immovable object; and on the other hand, there is a risk of encountering moving aircraft in flight in a mixed pattern. Right-hand patterns also are disfavored since the pilot, who is seated in the left-hand seat, will be on the "wrong" side of the aircraft for maximum visibility of the runway. It will be appropriate for the FAA to consider such matters in the change to a right-hand pattern for runway 26.

We note that the FAA has issued a security-related Temporary Flight Rule (TFR 4/0811), which directs that to the extent practicable pilots are to avoid over-flight, circling and loitering over power plants, refineries, industrial complexes, and military facilities. Although it will be up to the FAA whether and how the Rule is implemented, these types of facilities will need to be identified for pilots in some way. Identifying all these facilities on government-printed Sectional Charts would be daunting, and perhaps not desirable. Perhaps more likely, if the Flight Rule is to be fully implemented, these types of facilities will have to be identifiable from the air using a commonly recognized obstruction/avoidance marking.

The Commission is appropriately concerned for flight safety for student and experienced pilots as well as power plant security. Consequently, we seek through the Conditions of

Certification to create an *advisory* “No Fly Zone” over the power plant complex for security reasons in light of the TFR, but at a minimum, over the cooling towers for flight safety reasons.

Since the measures agreed-to by the Applicant require FAA approval, the Commission shall retain jurisdiction to impose or, as appropriate, seek the FAA’s imposition of alternate or additional measures if circumstances warrant.

MITIGATION:

☑ The Project Owner shall not commence construction of BEP II until the following are accomplished:

1. A remark is placed on the Airport’s Automated Surface Observation System (ASOS), or equivalent broadcast, advising pilots to avoid low-altitude direct overflight of the power plant;
2. The VFR traffic pattern to runway 26 is changed from left-hand turns to right-hand turns; and
3. A runway, other than runway 26, is designated as the primary calm wind runway. Condition: **TRANS-9**

Parking

Construction:
Parking for construction worker vehicles and the laydown area for construction supplies and equipment would be provided on 76 acres on the western side of BEP II plant site, including 10 acres for additional laydown space on the eastern side of the site. (FSA, p. 4.10-10)

MITIGATION:

☑ The Project Owner shall develop an off-site construction worker parking and materials staging plan. Condition: **TRANS-4.**

Operation: Adequate on-site parking is available for the twenty new power plant personnel.

Cumulative Impacts

The regional transportation system serving the BEP II area is operating at very efficient levels of service with significant reserve capacity. The three primary highways and the primary local arterial operate at LOS A. According to Caltrans staff, there will be several minor Caltrans construction and maintenance projects performed on the three highways (I-10, U.S. 95, and SR 78) in the vicinity of the BEP II site that would be used by BEP II construction traffic. Examples of the minor projects are: replacement of a railroad crossing, drainage improvements, and landscaping. A major project is rehabilitating 114 bridges on I-10 between the cities of Coachella and Blythe. **TRANS-5** would require that the project owner prepare a project construction traffic control plan in consultation with affected local jurisdictions and Caltrans. With implementation of **TRANS-5,** these Caltrans' projects would not result in a cumulative impact in combination with BEP II construction.

The Imperial Irrigation District (IID) is overseeing the Desert Southwest Transmission Line Project (DSWTP), a proposed new 118-mile transmission line from Buck Boulevard Substation (on the BEP I site) to the Southern California Edison Company's Devers Substation, approximately 10 miles north of Palm Springs. BEP II proposes to connect with the Buck Boulevard substation, which would connect with this new transmission line. The DSWTP would be constructed within an existing transmission line corridor. The project generally would be constructed parallel to existing major roads, and a majority of dirt access roads already exist. The DSWTP would cross various highways and local roads. IID project construction trucks may use highways that would also be used by BEP II construction trucks. Given the present low traffic volume on these roads, there would be no cumulative impact with BEP II construction.

In a separate license amendment proceeding by the BEP I owners, the Energy Commission is reviewing a proposal to construct a new transmission line from the BEP I power plant Buck Boulevard Substation that would proceed west about 60 miles to the Julian Hinds substation. An alternative line would proceed south about seven miles to the Central Valley Project Midpoint Substation. BEP II would not create any cumulatively considerable impacts on traffic and transportation. (FSA, p. 4.10-14-15)

<u>Findings</u>

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to traffic and transportation and all potential adverse traffic and transportation impacts will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

TRANS-1 The project owner shall comply with Caltrans and any affected jurisdiction's limitation on vehicle sizes and weights. In addition, the project owner or its contractor shall obtain necessary transportation permits from Caltrans and any affected jurisdiction for roadway use.

<u>Verification:</u> In the Monthly Compliance Reports (MCRs), the project owner shall submit copies of any transportation permits received during that reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file on site for at least six months after the start of commercial operation.

TRANS-2 The project owner or its contractor shall comply with Caltrans and any affected jurisdiction's requirement for encroachment into public rights-of-way and shall obtain necessary encroachment permits from Caltrans and any affected jurisdiction.

<u>Verification:</u> The project owner shall include in its Monthly Compliance Reports copies of encroachment permits received during the reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file on-site for at least six months after the start of commercial operation.

TRANS-3 The project owner shall ensure that permits and/or licenses are secured from the California Highway Patrol and Caltrans for the transport of hazardous materials.

<u>Verification:</u> The project owner shall include in its Monthly Compliance Reports, copies of all permits/licenses acquired by the project owner and/or subcontractors concerning the transport of hazardous substances.

TRANS-4 The project owner shall prepare a parking plan(s) for the pre-construction, construction and operation phases of the project in consultation with the City of Blythe. The project owner shall provide a copy of the City of Blythe's written comments and a copy of the parking plan(s) to the CPM.

The parking plan shall include a policy to be enforced by the project owner stating all project-related parking occurs on-site or in designated off-site parking areas as shown on the plan. The City shall have 30 calendar days to review the parking plan and provide written comments to the project owner.

<u>Verification:</u> At least 30 calendar days prior to site mobilization, the project owner shall provide a copy of the parking plan to the CPM for review and approval with documentation of review and comments by the City of Blythe.

TRANS-5 The project owner shall prepare a construction traffic control and implementation plan for the project and its associated facilities. The project owner shall consult with the affected local jurisdiction(s), Caltrans (if applicable) and the Blythe School District, in the preparation of the traffic control and implementation plan. The project owner shall provide a copy of the local jurisdiction's, Caltrans, and school district written comments and a copy of the traffic control and implementation plan to the CPM.

The traffic control and implementation plan shall include and describe the following minimum requirements:

- Timing of heavy equipment and building materials deliveries and related hauling routes;
- Redirecting construction traffic with a flag person;
- Signing, lighting, and traffic control device placement;
- Coordinating measures for eliminating any traffic safety hazards to school buses and school children on or near the construction worker travel and truck routes;
- Ensuring safe access to the main entrance;
- Ensuring access for emergency vehicles to the project site;

- Developing a emergency notification plan in case of a hazardous materials release including alternative transportation routes if I-10 was closed to traffic;
- Closing of travel lanes on a temporary basis;
- Ensuring access to adjacent residential and commercial property during the construction of all linear facilities; and
- Devising a construction workforce ridesharing plan.

The project owner shall submit the proposed traffic control and implementation plan to the affected local jurisdiction, school district(s) and Caltrans (if appropriate) for review and comment. The project owner shall provide to the CPM a copy of the transmittal letter submitted to the affected local jurisdiction, school district(s) and Caltrans requesting their review of the traffic control and implementation plan. The project owner shall provide any comment letters to the CPM for review and approval.

Verification: At least 30 calendar days prior to site mobilization, the project owner shall provide a copy of the traffic control and implementation plan to the CPM for review and approval with documentation of review and comment by the reviewing agencies. The reviewing agencies shall have 30 calendar days to review the plan.

TRANS-6 The project owner shall submit to the CPM for approval a private vehicular access easement (PVAE) plan securing a secondary vehicle access (at the minimum, to be used by emergency services vehicles). The installation/construction of the PVAE shall be completed to allow emergency services vehicles access to the power plant property at anytime.

The PVAE plan shall include a diagram that shows: the power plant property, the location and dimensions of the proposed PVAE, its connection to the public right-of-way and the proposed vehicle access road (driveway) on the power plant property. Also, the PVAE plan shall include copies of the executed PVAE and the executed PVAE maintenance/repair agreement with the affected property owner.

The project owner shall provide a copy of the PVAE plan to the affected local jurisdiction's public works department and affected fire protection department for review and comment. The project owner shall provide to the CPM a copy of the transmittal letter submitted to the local jurisdiction's public works department and fire protection department requesting their review of the PVAE plan.

Verification: At least 60 calendar days prior to the start of construction, the project owner shall provide to the CPM for review and approval a PVAE plan. Prior to the start of construction, the installation/construction of the PVAE shall be completed to allow emergency services vehicles access to the power plant property. Within 14 days after installation of the PVAE the project owner shall contact the CPM to request an inspection.

TRANS-7 The project owner shall repair affected public rights-of-way (e.g., highway, road, bicycle path, pedestrian path, etc.) to original or near original condition that has been damaged due to construction activities conducted for the project and its associated facilities.

Prior to start of site mobilization, the project owner shall notify the affected local jurisdiction(s) and Caltrans (if applicable) about their schedule for project construction. The purpose of this notification is to request the City of Blythe and Caltrans to consider postponement of public right-of-way repair or improvement activities until after project construction has taken place and to coordinate construction related activities associated with the applicable identified local jurisdiction or Caltrans project(s) with the project owner.

Prior to the start of site mobilization, the project owner shall photograph, or videotape the following public right-of-way segments and intersections: Hobsonway West between Neighbors Boulevard and Buck Boulevard, and Riverside Avenue from Neighbors Boulevard Buck Boulevard. The project owner shall provide the CPM, the affected local jurisdiction(s) and Caltrans (if applicable) with a copy of these images.

<u>Verification:</u> At least 30 calendar days before site mobilization, the project shall provide copies of the photographic images of the road segments noted above to the CPM, the affected local jurisdiction(s) and Caltrans (if applicable). Within 60 calendar days after completion of construction, the project owner shall meet with the CPM, the affected local jurisdiction(s) and Caltrans (if applicable) to identify sections of public right-of-way to be repaired, to establish a schedule to complete the repairs and to receive approval for the action(s). Following completion of any public right-of-way repairs, the project owner shall provide to the CPM a letter signed by the affected local jurisdiction(s) and Caltrans stating their satisfaction with the repairs.

TRANS-8 The project owner shall install lighting fixtures identical to those installed at BEP I pursuant to the City of Blythe's requirements and consistent with FAA requirements (FAA Advisory Circular 70/7460-1J).

<u>Verification:</u> At least thirty days prior to the start of HRSG stack construction, the project owner shall provide the City of Blythe, the Riverside Airport Land Use Commission, the FAA, and the Energy Commission's CPM a copy of the stack lighting plan.

TRANS-9 The Project Owner shall not commence construction of BEP II until the following are accomplished:

1. A remark is placed on the Airport's Automated Surface Observation System (ASOS), or equivalent broadcast, advising pilots to avoid low-altitude direct overflight of the power plant;
2. The VFR traffic pattern to runway 26 is changed from left-hand turns to right-hand turns; and
3. A runway, other than runway 26, is designated as the primary calm wind runway.

<u>Verification:</u> At least 60 days prior to the start of rough grading or construction, the Project Owner shall submit to the CPM documentation demonstrating the implementation of this condition.

TRAFFIC & TRANSPORTATION

APPLICABLE LAW	DESCRIPTION
FEDERAL	
49 CFR §171-177	Governs the transportation of hazardous materials, including the marking of the transportation vehicles.
14 CFR §77.13(2)(i)	Requires Applicant to notify FAA of any construction greater than an imaginary surface as defined by the FAA.
14 CFR 77.17	Requires Applicant to submit Form 7460-1 to the FAA.
14 CFR §§77.21, 77.23 & 77.25	Regulations that outline the obstruction standards that the FAA uses to determine whether an air navigation conflict exists.
STATE	
California State Planning Law, Government Code §65302	Requires each city and county to adopt a General Plan consisting of seven mandatory elements to guide its physical development, including a circulation element.
CA Vehicle Code §35780	Requires approval for a permit to transport oversized or excessive load over state highways.
CA Vehicle Code §31303	Requires transporters of hazardous materials to use the shortest route possible.
CA Vehicle Code §32105	Transporters of inhalation hazardous materials or explosive materials must obtain a Hazardous Materials Transportation License.
California Department of Transportation Traffic Manual, Section 5-1.1	Requires Traffic Control Plans to ensure continuity of traffic during roadway construction.
Streets and Highways Code, Division 2, Chapter 5.5, Sections 1460-1470	Requires Encroachment Permits for excavations in city streets.

LOCAL	
City of Blythe, General Plan, Circulation Element	Maintain optimal Levels Of Service; promote use of non-single occupant modes of transportation
Riverside County Airport Comprehensive Land Use Plan	Land use safety compatibility criteria are to minimize risks associated with an off-airport aircraft accident in the airport vicinity.

VISUAL RESOURCES – Summary of Findings and Conditions

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Objectionable Appearance	**MITIGATION**	**None**	**YES**
	Construction: Construction equipment at the power plant site will have a temporary, and thus insignificant, visual impact. Operation: Project structures will be unobtrusively painted. Vegetative screening will be planted to reduce the visibility of power plant features. **MITIGATION:** ☑ The Project Owner shall paint or treat project structures, buildings and components to minimize visual impacts. Condition: **VIS-4.** ☑ The Project Owner shall provide vegetative screening to reduce the visibility of power plant features. Condition: **VIS-5.** ☑ Consistent with aviation safety, the Project Owner will install minimal markings visible to the public. Condition: **VIS-7**.		
View Blockage	**None**	**None**	**YES**
	On eastbound I-10, the tall project structures would block lower portions of the background mountains, as well as portions of the existing BEP I. On Hobsonway, these project structures would briefly block motorists' views of background mountains. From Mesa Verde, the intervening distance results in little view blockage. From Central Blythe, there would be no view blockage.		
Scenic Designation	**None**	**None**	**YES**
	There are no scenic designations related to the project viewshed.		

Lighting	**MITIGATION**	**None**	**YES**
	Construction: Limited construction during nighttime hours will require lighting, which will be temporary, and thus insignificant. Operation: Power plant lighting could cause nighttime visual impacts, unless mitigated by designing hooded or shielded lighting consistent with worker safety. **MITIGATION**: ☑ Consistent with worker safety and security, the Project Owner shall direct night construction lighting inward toward work areas, using hooded or shielded lighting. Condition: **VIS-2.** ☑ The Project Owner shall design and install project lighting to minimize visibility from public viewing areas and to minimize illumination of the vicinity and the nighttime sky. Condition: **VIS-6.**		
Visible Plume	**Insignificant**	**Insignificant**	**YES**
	Visible plume formation would mainly occur during the cold weather months (November through April), with the majority of plume formation occurring during early morning and nighttime hours. Modeling predicts plume frequencies significantly less than 20% of seasonal clear hours, which is below the threshold of significance for visual impacts from plumes. The visibility of project plumes in the proximity of the Blythe Airport provides notice of the presence of potential plume turbulence.		

VISUAL RESOURCES - GENERAL

Visual resources analysis has an inherent subjective aspect. However, the use of generally accepted criteria for determining impact significance and a clearly described analytical approach aid in developing an analysis that can be readily understood.

The CEQA Guidelines define 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 (Cal. Code Regs. tit.14, § 15382).

BEP II would be located on the eastern lower tier of Palo Verde Mesa, which is characterized by a mostly undeveloped desert landscape of level terrain and sparse desert scrub vegetation interspersed with a small amount of irrigated agriculture and containing some industrial, utility, and transportation facilities. The most prominent built feature on the mesa is the recently constructed Florida Power and Light Blythe Energy Project (BEP I) with its prominent geometric forms and industrial character. Views of the mesa are panoramic in scope and encompass a landscape of generally uniform tan coloration interspersed with contrasting dark and light zones. Middle-ground views reveal a natural setting of stippled appearance due to the contrasts between vegetation, soil, and rock. Closer foreground views present a mosaic of sparse shrub vegetation and desert pavement openings.

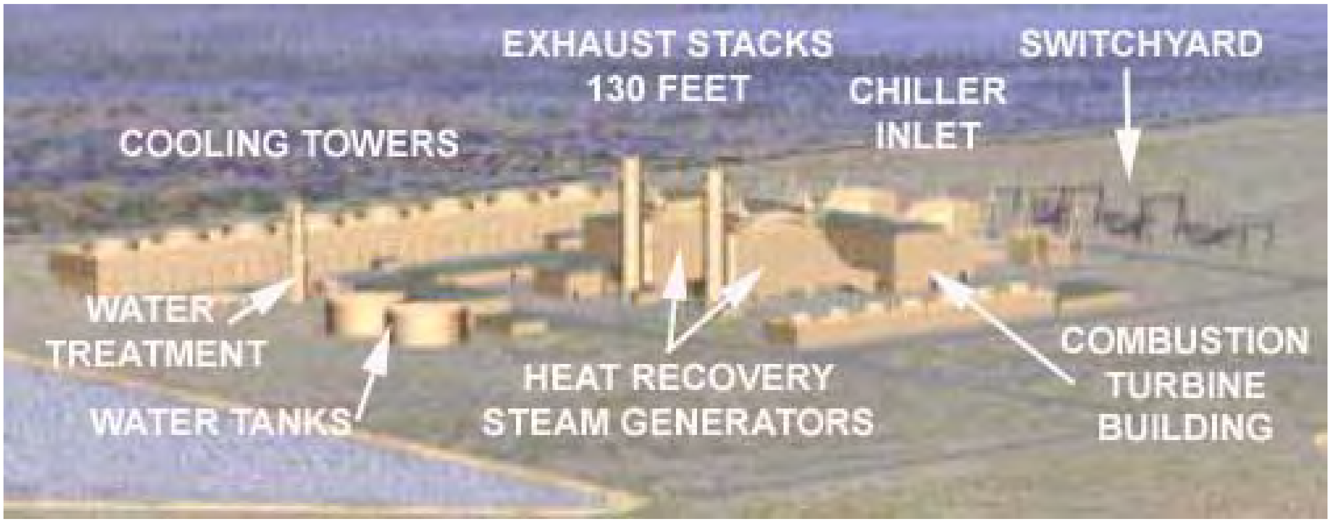
The project site and the surrounding landscape are characterized by views that are expansive, though views to the north are partially obstructed by the existing BEP I. Beyond the existing power plant and electric transmission infrastructure (Buck Boulevard Substation), structures are few and widely dispersed. Although the BEP II site is undeveloped, portions have been disturbed as a result of construction of BEP I. Several electric transmission lines cross the site supported on wood pole H-frame structures. To the east of the site is the Blythe Substation. Existing sewage oxidation ponds are located to the west of the site, but are not generally visible from either Hobsonway or I-10.

Objectionable Appearance

Construction: Construction of the proposed power plant would cause temporary visual impacts due to the presence of equipment, materials, and workforce. These impacts would occur at the proposed power plant site and construction laydown areas over a 20-month period of time. The construction of the proposed power plant would cause visual impacts. Construction would include site clearing and grading, construction of the actual facilities, and site cleanup and restoration. Construction would involve the use of cranes, heavy construction equipment, temporary storage and office facilities, and temporary laydown/staging areas. These structures and pieces of equipment will be stored on land adjacent to the project site in an area already exhibiting industrial (BEP I) visual character. Construction activities are anticipated to take place at night.

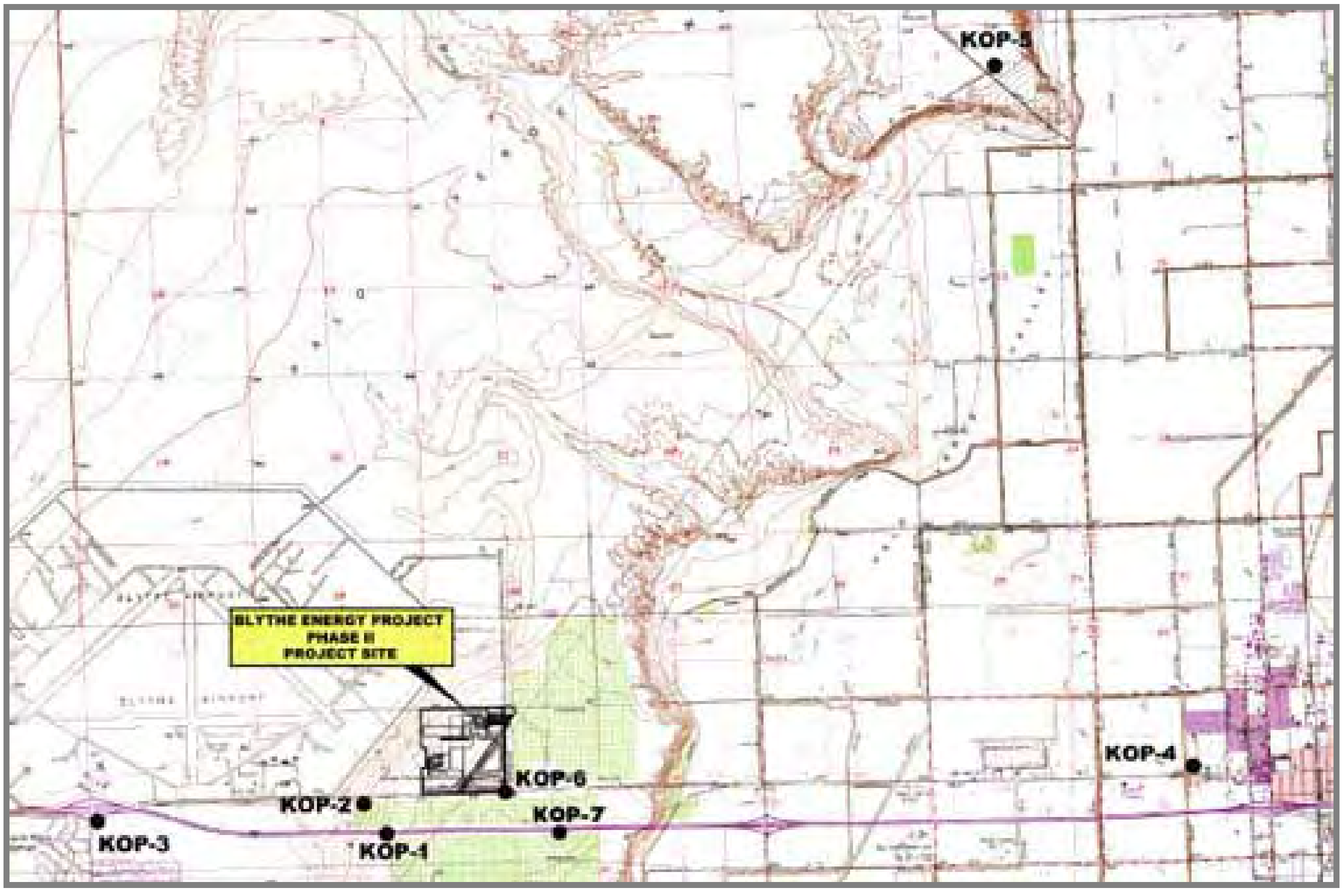
Traffic would also increase along Hobsonway during construction. Construction activities would be visible from Hobsonway, nearby residences, and I-10, which is the primary travel corridor in the region. The visual impacts associated with project construction are less than significant. (FSA, p. 4.12-14)

Operation:
The major components of the project include two combustion turbine generators, two heat recovery steam generators (HRSG), a steam turbine, an on-site transmission line, and other equipment. The most notable feature of the project is the HRSG exhaust stacks (130 feet high), which would be the most visible.



Viewer Exposure
The majority of viewers of the site would be motorists on I-10, located approximately 0.25-mile south of the project site; commercial areas on the east side of Blythe Airport; and rural residences to the west. The taller portions of the plant facilities would be visible at distances greater than 10 miles because of the relatively flat terrain and minimal view obstructions. (FSA, p. 4.12-4)

There are three rural residences located within one mile of the plant site and 32 residences located between one mile and two miles of the site. There are 112 residences between two to four miles from the site, and an additional 77 residences located between four and five miles from the site. Of these residences, there are 31 residences that would have views of the plant. (FSA, p. 4.12-5)



Key Observation Points
Various Key Observation Points (KOPs) were selected by the Applicant and by the Energy Commission staff. The following paragraphs briefly summarize the concluding assessments of overall visual sensitivity at these KOPs. Overall visual sensitivity takes into account existing landscape visual quality, viewer concern, and overall viewer exposure.

KOP 1 Eastbound I-10
KOP 1 is located on eastbound I-10, approximately 0.3-mile southwest of the project site and immediately east of the upper mesa eastern face. The view is to the northeast. This location provides an open and unobstructed view of the site. The foreground to middle ground terrain is flat and supports sparse desert scrub vegetation. The project would be visible in the foreground along with a number of existing transmission line structures, the Blythe Substation, and BEP I, which is the dominant feature in the landscape. The distant Dome Rock Mountains provide a backdrop of angular landforms[2]. (FSA, p. 4.12-6)

[2] The KOP 1 "after" photo-simulation of the project was presented in the Applicant's AFC and re-used by the Staff in its FSA. It appears the photo-simulation "hides" BEP I and thus represents only a split-second view for a motorist on I-10. There is no KOP 1 photo-simulation in the record that shows the effect of BEP II with BEP I together from I-10 in the way discussed in the narrative testimony.

BEP II views are unimpeded. The general lack of scenic features or elements of visual interest, combined with the presence of BEP I, numerous transmission line structures, utility poles, and the Blythe Substation contribute to a low-to-moderate rating for visual quality. Views also include the high traffic volumes and large trucks with containers of rectangular block form on I-10. Of the approximately 16,300 to 17,100 motorists per day on I-10, about 40 percent are heavy trucks. The number of viewers is high and the view duration for eastbound motorists on I-10 would be moderate. For viewers at KOP 1, the overall effect is moderate visual sensitivity of the visual setting and viewing characteristics. (FSA pp. 4.12-6-7)

When considered within the context of the overall moderate visual sensitivity of the existing landscape and viewing characteristics, the low-to-moderate visual change that would be perceived from KOP 1 would cause an adverse but less than significant visual impact with the effective implementation of mitigation measures (1) to blend the color of structures with the landscape and reduce glare and (2) to plant trees and bushes for screening. (FSA, p. 4.12-16)

KOP2 Eastbound Hobsonway

KOP 2 is located on Hobsonway, near a residence that is located on the eastern face of the mesa's upper tier, approximately 0.4 mile west of the project site. The view is to the east-northeast. This location provides a slightly elevated view over the site that is open and unobstructed. The foreground to middle-ground terrain is flat and supports sparse desert scrub vegetation. The project would be visible in the foreground along with a number of existing transmission line structures, the recently completed BEP I, Blythe Substation, and the paved lanes of Hobsonway. Other roadside utility poles are visible as they transition from the foreground to background away from the viewer along the north side of Hobsonway. To the east, the Dome Rock Mountains are visible as distant background elements. (FSA, p. 4.12-7)

The most prominent landscape features are the recently constructed BEP I[3] with its industrial character and the narrow, linear ribbon of gray pavement that comprises Hobsonway. Portions of the Palo Verde Valley are visible in the background and the distant Dome Rock Mountains provide a backdrop of angular landforms that add some visual variety and interest. The tan desert soils and dark greenish-brown desert scrub vegetation are the dominant coloration in a landscape generally lacking vivid coloration or color contrast.

The limited visibility of scenic features and elements of visual interest combined with the presence of BEP I, numerous transmission line structures, utility poles, and Blythe Substation contribute to a low-to-moderate rating for visual quality. Viewer expectations at this location are conditioned by the vicinity landscape along Hobsonway, which includes a panoramic landscape of prominent energy generation and transmission infrastructure and occasional geometric block forms such as the existing commercial establishment and facilities adjacent to the airport (which are not visible from KOP 2). Viewers are also aware of the high traffic volumes and large trucks with containers of rectangular block form on I-10. However, any increase in industrial character would be seen as an adverse visual change.

Viewer sensitivity is rated low-to-moderate for motorists on Hobsonway. Site visibility is high in that the view of the site from KOP 2 is slightly elevated and generally unobstructed at a foreground viewing distance. While the number of viewers is low, the view duration for eastbound motorists on Hobsonway would be extended with a direct angle of view. The high visibility and extended duration of view would be somewhat moderated by the low numbers of viewers. Therefore, viewer exposure would be moderate-to-high for motorists on Hobsonway. For eastbound motorists at KOP 2, the low-to-moderate visual quality and

[3] The KOP 2 "after" photo-simulation of the project was presented in the Applicant's AFC and re-used by the Staff in its FSA. It appears the photo-simulation "hides" BEP I and thus represents only a split-second view for a motorist on Hobsonway. There is no KOP 2 photo-simulation in the record that shows the effect of BEP II with BEP I together from I-10 in the way discussed in the narrative testimony.

viewer concern, combined with moderate-to-high viewer exposure, result in an overall moderate visual sensitivity. (FSA, p. 4.12-7)

When considered within the context of the overall moderate visual sensitivity of the existing visual landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 2 would cause an adverse but less than significant visual impact with the effective implementation of mitigation measures (1) to blend the color of structures with the landscape and reduce glare and (2) to plant trees and bushes for screening. (FSA, p. 4.12-17)

KOP 3 Mesa Verde (Nicholls Warm Springs)

KOP 3 captures the potential visual impact to the nearest major residential area. The Mesa Verde (Nicholls Warm Springs) residential subdivision is located south of Blythe Municipal Airport, adjacent and to the south of I-10. KOP 3 was established on the north side of the subdivision at a distance of approximately 2.5 miles southwest of the project site. A number of residences along the north and east perimeter of the subdivision would have distant, indirect views of the proposed project. The viewshed to the northeast from KOP 3 includes the characteristic sparsely vegetated, tan-colored desert landscape in the foreground to middle ground, a few structures on the north side of I-10 adjacent to the airport, and several transmission lines extending across the flat desert landscape and the recently completed BEP I. The Blythe Substation is barely discernible in the background. (FSA, p. 4.12-8)

Views to the northeast from the north side of the Mesa Verde residential subdivision encompass foreground to background panoramic scenes of a broad, level, desert mesa landscape with a dominant monotone tan coloration and lacking distinctive features.

I-10 features prominently in the foreground to middle ground landscape. The viewshed is typical of the region and is punctuated by energy transmission infrastructure and facilities associated with Blythe Municipal Airport. Noticeable at a distance is the complex industrial appearance of BEP I. Although barely visible above the horizon, the distant Big Maria and Dome Rock Mountains provide a faint backdrop of angular landforms of lavender coloration. The lack of vivid coloration and the limited visibility of scenic features and color contrast, or elements of visual interest, combined with the presence of energy and transportation infrastructure contribute to a low-to-moderate rating for visual quality.

Although residential uses are generally attributed a high degree of viewer concern, viewer concern is also conditioned by existing landscape characteristics and quality, visibility, and primary view direction. At the Mesa Verde Subdivision, most primary (front of residence) views along the north and east side of the subdivision (represented by KOP 3) are directed to the south and west away from the direction of the proposed project. Also, the project is located at a substantial distance (2.5 to 3 miles) from the subdivision, thus reducing project visibility. Between the project and the subdivision, I-10 has a continuous flow of vehicles, many of which are large tractor-trailers with large containers of rectangular, geometric form. Also present in northern views from the subdivision are structures on the north side of I-10 in close proximity to Blythe Airport. Views in the direction of the proposed project encompass numerous built features including BEP I, thus, tempering viewer expectations and lowering viewer concern to a moderate level at KOP 3.

Project visibility is low due to the substantial distance between KOP 3 and the proposed project and the partial screening that occurs from a continual stream of vehicles on I-10, which intervenes between the viewer and the project site. The low project visibility at this background viewing distance combined with the low-to-moderate number of viewers with potentially extended views results in an overall moderate viewer exposure at KOP 3.

From the north side of the Mesa Verde residential development, the low-to-moderate visual quality combined with moderate viewer concern and moderate viewer exposure, lead to a moderate overall visual sensitivity of the visual setting and viewing characteristics. (FSA, pp. 4.12-8-9)

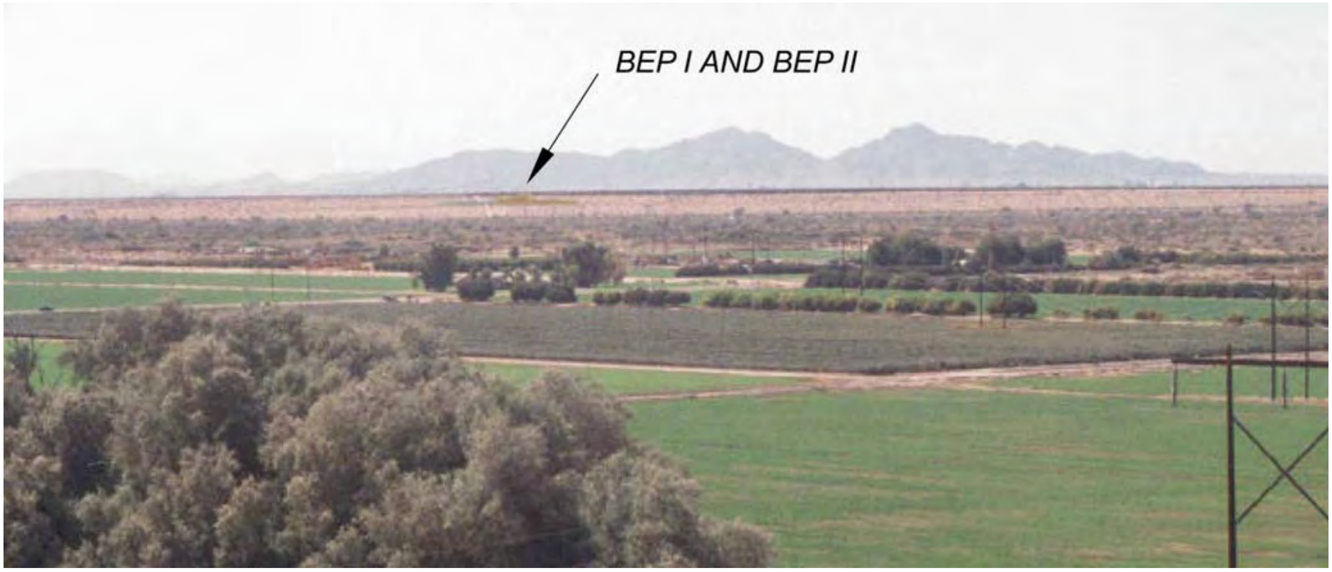
When considered within the context of the moderate visual sensitivity of the existing landscape and viewing characteristics, the low visual change that would be perceived from KOP 3 would cause an adverse but less than significant visual impact with the effective implementation of mitigation measures (1) to blend the color of structures with the landscape and reduce glare and (2) to plant trees and bushes for screening.

KOP 4 Central Blythe

KOP 4 is located just north of Hobsonway on the “C” Canal east levee, adjacent to the K-Mart Store parking lot. This location is approximately four miles east of the project site and depicts the closest view of the site from the City of Blythe urban center. As the photo-simulation shows, the BEP II project is essentially not visible from this location, principally due to intervening trees. (FSA, pp. 4.12-9, 18)

KOP 5 Blythe Municipal Golf Course & Mesa Bluffs Residences
KOP 5 was selected to characterize the impact to the Blythe Municipal Golf Course and the adjacent Mesa Bluffs residences, all of which are located on Palo Verde Mesa and have a direct, though distant (at approximately 4.5 miles), line-of-sight to the proposed plant site. KOP 5 is located in a small parking area adjacent to the Golf Course and several residences at the edge of the mesa.

This location provides a panoramic view to the south and southwest, encompassing the Palo Verde Valley in the foreground and middle ground and the project site in the background. The Mule and Little Chuckwalla Mountains provide a distant backdrop to the site. The foreground to middle ground terrain is flat and supports sparse desert scrub vegetation and a few irrigated agricultural parcels. Also visible in the distance is the City of Blythe, the airport, the Blythe Substation, numerous electric transmission lines that cross the site, and BEP I. At this distance, BEP I, the substation, and transmission lines are barely discernible. The view to the site from several residences and several of the golf course fairways and greens would be direct and extended. (FSA, p. 4.12-10)



The panoramic views to the south and southwest overlook the Palo Verde Valley and Palo Verde Mesa. These vista views also encompass the mountains that ring the area. Although agricultural fields and monotone desert scrub vegetation dominate much of the foreground to middle ground landscape, the elevated perspective available from this KOP provides visual access to a regional landscape that offers more distinctive features with greater visual variety and interest. The color contrast of the tan soils and vegetation with the vivid green of irrigated croplands and the lavender of distant mountain ranges add to a more visually interesting landscape. Also, barely discernible at this background distance is BEP I. Visual quality from KOP 5 is rated moderate-to-high.

Residences in the Mesa Bluffs area are situated along the mesa edge to take advantage of the vistas overlooking the Palo Verde Valley and Mesa. Also, the recreational users of the Municipal Golf Course (approximately 36,000 rounds of golf are played annually) have expectations for panoramic views and a predominantly naturally appearing landscape. Therefore, the viewers in the Mesa Bluffs area are considered to be sensitive to landscape changes and viewer concern is rated moderate-to-high.

Site visibility is low due to the substantial distance between the golf course/Mesa Bluffs area and the project site. Although the number of potential viewers at the golf course is moderate, the site would only be visible from a few of the fairways and greens and would generally not be noticeable given the distance and indirect angle of view. The adjacent residences would have more direct viewing opportunities, but the distance would generally limit project visibility. However, the low project visibility would offset the extended duration of view available to residents and golfers alike. Therefore, viewer exposure is low-to-moderate.

For viewers along Mesa Bluffs, the moderate-to-high visual quality and viewer concern combined with the low-to- moderate viewer exposure, lead to a moderate-to-high assessment for overall visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 5. (FSA, pp. 4.12-10-11)

When considered within the context of the overall moderate-to-high visual sensitivity of the existing landscape and viewing characteristics, a low visual change would be perceived from KOP 5 and would not generate a significant visual impact. (FSA, p. 4.12-19)

KOP 6 Westbound Hobsonway

KOP 6 was selected as one of two locations to characterize the impact to motorists on Hobsonway. KOP 6 is located on westbound Hobsonway at the southeast corner of the project site and captures the view of the site available to westbound motorists.

This location provides a panoramic view to the north and west encompassing the project site in the foreground and the Little Maria and Big Maria Mountains as distant background elements. The foreground to middle ground terrain is flat and dominated by BEP I. Numerous electric transmission lines also cross the foreground landscape. Due to the close proximity of the site to Hobsonway, the site is located within the primary cone of vision of westbound travelers on Hobsonway. (FSA, p. 4.12-11)

Views to the north and west from Hobsonway encompass foreground to middle-ground panoramic scenes of a highly modified desert mesa environment that is dominated by energy generation and transmission infrastructure. While the immediate foreground lacks scenic features or elements of visual interest, the angular landforms of the distant Little Maria and Big Maria Mountains add some visual variety and interest though they appear low on the horizon. Portions of these features are blocked from view by the industrial forms of BEP I. The lack of vivid coloration, and the limited visibility of scenic features and elements of visual interest, combined with the dominant presence of BEP I and numerous transmission line structures, and Blythe Substation result in a low-to-moderate rating for visual quality.

Viewer expectations along this portion of Hobsonway are conditioned by the vicinity landscape and must now consider the prominent presence of BEP I along with the numerous electric transmission line structures and Blythe Substation. Viewers are also aware of the high traffic volumes and large trucks with containers of rectangular block form on I-10. Overall viewer concern is rated low-to-moderate.

As previously stated, for travelers on Hobsonway, the proposed site would be highly visible at this foreground viewing distance. Although the number of viewers would be low, the duration of view would be moderate to high. The overall viewer exposure would be moderate. (FSA, p. 4.12-11-12)

When considered within the context of the overall low-to-moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 6 would cause an adverse but less than significant visual impact with the effective implementation of mitigation measures (1) to blend the color of structures with the landscape and reduce glare and (2) to plant trees and bushes for screening. (FSA, p. 4.12-20)

KOP 7 Westbound I-10
KOP 7 was selected as one of two locations to characterize the impact to motorists on I-10. KOP 7 is located on westbound I-10, approximately 0.4-mile southeast of the project site and captures the view of the site available to westbound motorists.

This location provides a panoramic view to the northwest encompassing the project site in the foreground with the prominent BEP I in the near middle ground, and the Little Maria and Big Maria Mountains as distant background elements. The foreground landscape is also crossed by numerous electric transmission lines. The site is visible within the primary cone of vision of westbound travelers on I-10. (FSA, pp. 4.12-12-13)

Views to the northwest from I-10 encompass foreground to middle ground panoramic desert mesa scenes with prominent energy generation and transmission infrastructure. While the immediate foreground lacks scenic features or elements of visual interest, the angular landforms of the distant Little Maria and Big Maria Mountains add some visual variety and interest though they appear low on the horizon. A small portion of the mountains in the background are blocked from view by the industrial forms of BEP I. The lack of vivid coloration, and the limited visibility of scenic features and elements of visual interest, combined with the dominant presence of BEP I, numerous transmission line structures, and Blythe Substation result in a low-to-moderate rating for visual quality.

Viewer expectations along this portion of I-10 are conditioned by the adjacent landscape and must now consider the prominent presence of the recently completed BEP I along with the numerous electric transmission line structures and Blythe Substation. Viewers are also aware of the high traffic volumes and large trucks with containers of rectangular block form on I-10. Overall viewer concern is rated low-to-moderate.

As previously stated, the proposed site is located within the primary cone of vision of travelers on I-10 and visibility would be high at this foreground viewing distance. The peak month average daily traffic (ADT) for the month of heaviest traffic flow at the intersection Junction Route 78 south/Neighbors Boulevard on I-10 is 26,000 vehicles according to Caltrans information. The number of viewers would be high and the duration of view would be moderate. The overall viewer exposure would be moderate-to-high.

For westbound motorists on I-10, the low-to-moderate visual quality and viewer concern combined with moderate-to-high viewer exposure result in a moderate visual sensitivity of the existing landscape and viewing characteristics as viewed from KOP 7. (FSA, pp. 4.12-12-13)

When considered within the context of the overall moderate visual sensitivity of the existing landscape and viewing characteristics, the moderate-to-high visual change that would be perceived from KOP 7 would cause an adverse but less than significant visual impact with the effective implementation of mitigation measures (1) to blend the color of structures with the landscape and reduce glare and (2) to plant trees and bushes for screening. (FSA, 4.12-21)

Aviation Obstruction Markings

As discussed in the **TRAFFIC & TRANSPORTATION** section, for pilot safety at the Blythe Airport, the Commission may employ obstruction markings on one or more project structures. Aviation safety is an overriding concern compared to the visual impacts of the avoidance markings on any project-related structure.

MITIGATION:

- ☑ The Project Owner shall paint or treat project structures, buildings and components to minimize visual impacts. Condition: **VIS-4.**
- ☑ The Project Owner shall provide vegetative screening to reduce the visibility of power plant features. Condition: **VIS-5.**
- ☑ Consistent with worker safety and security, the Project Owner shall design and install project lighting to minimize visibility from public viewing areas and to minimize illumination of the vicinity and the nighttime sky. Condition**: VIS-6.**
- ☑ Consistent with aviation safety, the Project Owner will install minimal signage visible to the public. Condition: **VIS-7**.

View Blockage

View blockage describes the extent to which any previously visible landscape features are blocked from view by the project. Blockage of higher quality landscape features by lower quality features causes adverse impacts.

From the vicinity of KOP 1 (Eastbound I-10), the HRSG structures and stacks and cooling tower (lower quality landscape features) would block portions of the background mountains and sky (higher quality landscape features) as well as portions of the existing BEP I (similar quality feature). The resulting view blockage would be low-to-moderate. From KOP 2 (Eastbound Hobsonway), the HRSG structures and stacks and cooling tower would block noticeable portions of the Dome Rock Mountains to the east and sky (higher quality landscape features). The resulting view blockage would be moderate. As viewed from KOP 3 (Mesa Verde), the small profile of the proposed project and minimal skylining that would occur would result in a low degree of view blockage. From KOP 4 (Central Blythe), there would be no view blockage since the project components would not be visible. (FSA, pp. 4.12-15 - 18)

As viewed from KOP 5 (Golf Course & Residence), the small profile of the proposed project would result in minimal blockage of the mountain backdrop and overall view blockage would be low. From KOP 6 (Westbound Hobsonway), project structures would block a substantial portion of the background mountain range (higher quality landscape feature). The resulting view blockage would be moderate. Lastly, from KOP 7 (Westbound I-10), project structures would block a substantial portion of the background mountain range (higher quality landscape feature). The resulting view blockage would be moderate in the wide field of view. Overall, therefore, the project would cause very limited view blockage, at a level of insignificance. (FSA, pp. 4.12-19-21)

Scenic Designation

Although panoramic vistas are available to users of the Blythe Municipal Golf Course and to the adjacent residences at Mesa Bluffs, there are no recognized scenic vistas in the project viewshed. Therefore, the project would not cause significant visual impacts in regard to this criterion.

The foreground to middle-ground mesa landscape consists primarily of desert scrub vegetation with a substantial amount of electric transmission infrastructure and other built features (including roads and structures). Views from the nearby residences off of Hobsonway and from Hobsonway and I-10 are not considered scenic. The project site is not within a designated State scenic highway. Therefore, the project would not cause significant visual impacts in regard to this criterion. (FSA, pp. 4.12-14)

Lighting

Construction: Construction during nighttime hours will require lighting. The temporary nature of night construction together with measures to reduce light leaving the construction site render night construction lighting impacts insignificant. (FSA, p. 4.12-14)

MITIGATION:

☑ Consistent with worker safety and security, the Project Owner shall direct night construction lighting inward toward work areas, using hooded or shielded lighting. Condition: **VIS-2.**

Operation: The project's lighting system will provide illumination for the performance of general outdoor yard tasks, safety, plant security and general site roadway access and will consist of sodium lights and support poles. A low visibility lighting scheme using shielded, high cut-off angle fixtures will be utilized to minimize the nighttime impact on nearby properties. Additional control measures such as timers, motion sensors, and/or switches will be used to keep lights off when they are not needed. Access roads from Buck Boulevard through the plant will be illuminated. The Applicant has agreed with the City of Blythe to provide street lighting along Buck Boulevard and Hobsonway. The Applicant has decided to install FAA approved lighting at the tops of the HRSG exhaust stacks. (FSA, p. 4.12-22)

Project night lighting would be visible from several of the KOPs and their represented areas (KOPs 1, 2, 3, 5, 6, and 7). Given the limited amount of night lighting in the vicinity of the power plant site, the proposed project lighting has the potential to further change the character of the existing landscape at night both during construction and operation of the project, potentially resulting in significant visual impacts. Properly directed and shielded lighting elements would ensure that the visual impacts associated with operational lighting remain less than significant. (FSA, pp. 4.12-21-22)

MITIGATION:

- ☑ Consistent with worker safety and security, the Project Owner shall design and install project lighting to minimize visibility from public viewing areas and to minimize illumination of the vicinity and the nighttime sky. Condition**: VIS-6.**

Visible Plumes

Energy Commission staff modeled the cooling tower plume frequency using the Combustion Stack Visible Plume (CSVP) model, with a three-year (1989-1991) meteorological data set for Blythe Airport. These modeling results indicate that the visible plume formation would mainly occur during the cold weather months, with the majority of plume formation occurring during early morning and nighttime hours. For the proposed cooling tower, the maximum temperature where a visible plume is predicted is 81°F when the relative humidity is 88%.

For the Limited Duct Firing case, considered a reasonable worst-case for plume formation because it assumes duct firing for all ambient conditions above 50°F, the seasonal daylight clear hour plume frequency was determined to be 10.7%. This is below the Energy Commission's 20% threshold that would trigger a plume dimension modeling analysis and a visual impact analysis. Visible plumes occurring less than 20 percent are less than significant. (FSA, pp. 4.12-23, 50-51)

Staff also modeled the HRSG plumes using the same CSVP model. Per the Applicant's discussion regarding the operating assumptions for the HRSGs, the duct burners will not be operational at ambient temperatures less than 50°F due to steam turbine flow limitations. For the proposed HRSGs operating with duct firing at temperatures of 50°F or greater, no visible steam plumes were predicted to occur.

Visible plume formation would mainly occur during the cold weather months, with the majority of plume formation occurring during early morning and nighttime hours. For the proposed HRSG operating without duct firing, the maximum temperature where a visible plume is predicted is 42°F when the relative humidity is 100%.

A plume frequency of 20% of seasonal (November through April) daylight clear is used as a threshold trigger. The CSVP model predicts plume frequencies significantly less than 20% of seasonal clear hours, which does not trigger additional study of the visual impacts of the plumes from the HRSGs. (FSA, pp. 4.12-51-52)

Cumulative Impacts

Cumulative impacts to visual resources would occur where project facilities or activities (such as construction) occupy the same field of view as other built facilities or impacted landscapes. It is also possible that a cumulative impact could occur if a viewer's perception is that the general visual quality of an area is diminished by the proliferation of visible structures (or construction effects such as disturbed vegetation), even if the new structures are not within the same field of view as the existing structures. The significance of the cumulative impact would depend on the degree to which (1) the viewshed is altered; (2) visual access to scenic resources is impaired; (3) visual quality is diminished; or (4) the project's visual contrast is increased.

Three projects were identified for the cumulative impact analysis: the existing BEP I, the proposed BEP I Transmission Line Amendment Project (BEPTL), and the Desert Southwest Transmission Project (DSWTP), including both its substation and the transmission line. BEP II would be visible within the same field of view as BEP I and would make a substantial additional contribution to the visual impact resulting from BEP I. BEP II is closer than BEP I to Hobsonway, a nearby residence, and I-10. As a result, BEP II would appear larger in scale and more prominent.

The proposed Blythe Energy Project Transmission Line (BEPTL) from the Buck Boulevard Substation to the Julian Hinds Substation would be adjacent to the existing SCE DPV-1 500-kV line within a designated U.S. Bureau of Land Management utility corridor. Two other transmission lines are proposed within the same utility corridor; the SCE DPV-2 and the DSWTP 500 kV. The specific location of the proposed DSWTP 500 kV has not been identified. The proposed transmission lines would contribute an industrial character to the I-10 corridor, particularly along the section of I-10 west of Desert Center.

The BEPTL would be 1.5 to 2 miles south from I-10 viewers. This distance and direction helps to minimize the visual cumulative impact to travelers on I-10 and from the BEP II site. The transmission line route passes within the boundary of the Palo Verde Valley Area Plan - Blythe Airport Sphere of Influence Policy Area. The airport property adjoins the project site. The transmission line's design and construction within this plan area is required to comply with applicable airport operation(s) and aviation safety regulations.

The existing Blythe Airport, BEP I and SCE DPV-1 500-kV line, and the proposed BEPTL, SCE DPV-2 and DSWTP 500 kV combined would present an expansive area of complex industrial character in an otherwise desert mesa landscape. The visual contrast, structural dominance, and view blockage resulting from the combined existing developments and proposed projects would cause a cumulative visual impact. However, based on the short duration of view for travelers on 1-10 and low number of viewers on Hobsonway, the proposed BEP II's impact when combined with the cumulative impact of other developments both existing and proposed, would not be cumulatively considerable, and thus does not result in a significant cumulative impact to visual resources. (FSA, p. 4.12-24)

Findings

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to visual resources and all potential adverse visual resource impacts will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

CONSTRUCTION SCREENING

VIS-1 Deleted

CONSTRUCTION LIGHTING

VIS-2 The project owner shall ensure that lighting for construction of the power plant is used in a manner that minimizes potential night lighting impacts, as follows:

a) All lighting shall be of minimum necessary brightness consistent with worker safety and security;

b) All fixed position lighting shall be shielded/hooded, and directed downward and toward the area to be illuminated to prevent direct illumination of the night sky and direct light trespass (direct light extending outside the boundaries of the power plant site or the site of construction of ancillary facilities, including any security related boundaries); and

c) Wherever feasible and safe and not needed for security, lighting shall be kept off when not in use.

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 requires modifications to the lighting, 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 the CPM with a complaint resolution form report as specified in the General Conditions section, including a proposal to resolve the complaint and a schedule for implementation. The project owner shall notify the CPM within 48 hours after completing implementation of the proposed resolution. A copy of the complaint resolution form report shall be included in the subsequent Monthly Compliance Report.

SITE SURFACE RESTORATION

VIS-3 Deleted. See **BIO-5(9)**

SURFACE TREATMENT OF PROJECT STRUCTURES AND BUILDINGS

VIS-4 The project owner shall treat the surfaces of all project structures and buildings visible to the public such that a) their color(s) minimize(s) visual intrusion and contrast by blending with the landscape; b) their colors and finishes do not create excessive glare; and c) their colors and finishes are consistent with local 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 for CPM review and approval a specific surface treatment plan that will satisfy these requirements. The 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, building, tank, pipe, and wall; the 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) One set of 11" x 17" color photo simulations at life size scale, of the treatment proposed for use on project structures, including structures treated during manufacture, from Key Observation Point(s) 2 and 6 (locations shown on Figures 6B and 10B of the Final Staff Assessment);

e) A specific schedule for completion of the treatment; and

f) A procedure to ensure proper treatment maintenance for the life of the project.

The project owner shall not specify to the vendors the treatment of any buildings or structures treated during manufacture, or perform the final treatment on any buildings or structures treated in the field, until the project owner receives notification of approval of the treatment plan by the CPM. Subsequent modifications to the treatment plan are prohibited without CPM approval.

<u>**Verification:**</u> At least 90 days prior to specifying to the vendor the color(s) and finish(es) of the first structures or buildings that are surface treated during manufacture, the project owner shall submit the proposed treatment plan to the CPM for review and approval and simultaneously to the City of Blythe for review and comment.

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.

Prior to 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 they are ready for inspection and shall submit one set of electronic color photographs from the same key observation points identified in (d) above.

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) maintenance activities that occurred during the reporting year; and c) the schedule of maintenance activities for the next year.

LANDSCAPE SCREENING

VIS-5 The project owner shall provide landscaping along the southern boundary of the Blythe II site that reduces the visibility of the power plant structures and complies with local policies and ordinances consistent with the landscaping at Blythe I. Trees and other vegetation consisting of informal groupings of fast-growing native species shall be strategically placed and of sufficient density to visually soften the industrial character of the power plant structures within the shortest feasible time. If any landscaping is installed along the western and northern boundaries of the Blythe II site, only native species shall be used.

The project owner shall submit to the CPM for review and approval and simultaneously to City of Blythe for review and comment a landscaping plan whose proper implementation will satisfy these requirements. The plan shall include:

a) A detailed landscape, grading, and irrigation plan, at a reasonable scale. The plan shall demonstrate how the requirements stated above shall be met. The plan shall provide a detailed installation schedule demonstrating installation of as much of the landscaping as early in the construction process as is feasible in coordination with project construction.

b) A list (prepared by a qualified professional arborist familiar with local growing conditions) of proposed species, specifying installation sizes, growth rates, expected time to maturity, expected size at five years and at maturity, spacing, number, availability, and a discussion of the suitability of the plants for the site conditions and mitigation objectives, with the objective of providing the widest possible range of species from which to choose;

c) Maintenance procedures, including any needed irrigation and a plan for routine annual or semi-annual debris removal for the life of the project;

d) A procedure for monitoring for and replacement of unsuccessful plantings for the life of the project.

The plan shall not be implemented until the project owner receives final approval from the CPM.

<u>Verification:</u> The landscaping plan shall be submitted to the CPM for review and approval and simultaneously to the City of Blythe for review and comment at least 90 days prior to installation. If the CPM determines that the plan requires revision, the project owner shall provide to the CPM and simultaneously to the City of Blythe a revised plan for review and approval by the CPM.

The planting must occur during the first optimal planting season following site mobilization. The project owner shall simultaneously notify the CPM and the City of Blythe within seven days after completing installation of the landscaping, that the landscaping is ready for inspection. The project owner shall report landscape maintenance activities, including replacement of dead or dying vegetation, for the previous year of operation in each Annual Compliance Report.

PERMANENT EXTERIOR LIGHTING

VIS-6 To the extent feasible, consistent with safety and security considerations, 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) the plan complies with local policies and ordinances.

The project owner shall submit to the CPM for review and approval and simultaneously to the City of Blythe for review and comment a lighting mitigation plan that includes the following:

(1) Location and direction of light fixtures shall take the lighting mitigation requirements into account;

(2) Lighting design shall consider setbacks of project features from the site boundary to aid in satisfying the lighting mitigation requirements;

(3) Lighting shall incorporate fixture hoods/shielding, with light directed downward or toward the area to be illuminated;

(4) Light fixtures shall not cause obtrusive spill light beyond the project boundary.

(5) All lighting shall be of minimum necessary brightness consistent with operational safety and security; and

(6) 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 90 days prior to ordering any permanent exterior lighting, the project owner shall contact the CPM to discuss the documentation required in the lighting mitigation plan. At least 60 days prior to ordering any permanent exterior lighting, the project owner shall submit to the CPM for review and approval and simultaneously to the City of Blythe for review and comment a lighting mitigation plan. If the CPM determines that the plan requires revision, the project owner shall provide to the CPM a revised plan for review and approval by the CPM. The project owner shall not order any exterior lighting until receiving CPM approval of the lighting mitigation plan. Prior to commercial operation, the project owner shall notify the CPM that the lighting has been completed 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 that notification the project owner shall implement the modifications and notify the CPM that the modifications have been completed and are ready for inspection.

Within 48 hours 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. A copy of the complaint resolution form report shall be submitted to the CPM within 30 days of complaint resolution.

SIGNAGE

VIS-7 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 policies and ordinances of the City of Blythe. The design of any signs required by safety regulations shall conform to the criteria established by those regulations.

Verification: Prior to installation of the sign, the project owner shall provide a copy of the plans for the sign to the City of Blythe for review and comment and to the CPM for review and approval.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

VISUAL RESOURCES

APPLICABLE LAW	DESCRIPTION
FEDERAL	
NA	There are no applicable Federal LORS for the section of visual.
STATE	
California Coastal Act, Section 30251	Describes view and visual enhancement requirements for permitted development
LOCAL	
Riverside County, Palo Verde Valley Area Plan	The Plan guides the evolving character of this expansive agricultural and desert area, including applying design standards for projects adjacent to Scenic Highways. The Plan designates the Blythe Airport Influence Policy Area and includes development restrictions.
City of Blythe, General Plan	The site has been designated as Heavy Industrial (I-H), allowing intense industrial uses.

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WASTE MANAGEMENT – Summary of Findings and Conditions

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Excavation	**MITIGATION**	**None**	**YES**
	An Environmental Site Assessment shows there is no evidence of the release of contamination onto soils on-site. However, contaminants are present at a nearby World War II era landfill site. Thus, it is possible that contaminated soil may be encountered during the excavation for the project's foundation. **MITIGATION:** ☑ The Project Owner and contractor, if necessary, will obtain a hazardous waste generator identification number. Condition: **WASTE-3** ☑ The Project Owner shall employ a registered engineer and prepare a waste management plan and a site remediation plan. Conditions: **WASTE-1** to **WASTE-5** ☑ Any contaminated soils will be tested and, if appropriate, treated or disposed at a Class I landfill. Conditions: **WASTE-2**		
Construction Wastes	**MITIGATION**	**None**	**YES**
	Power plant construction will generate typical construction wastes, such as lumber, plastic, scrap metal, glass, excess concrete, empty containers, and packaging. These construction wastes are either recycled or disposed at the Blythe landfill. **MITIGATION:** ☑ The Project Owner shall prepare a waste management plan to assure the appropriate handling of construction wastes. Condition: **WASTE-5**. ☑ The Project Owner and contractor, if necessary, will obtain a hazardous waste generator identification number. Condition: **WASTE-3**		
Non-hazardous Operational Wastes	**Insignificant**	**None**	**YES**
	Typical non-hazardous operation wastes include a small volume of maintenance-related trash, office trash, empty containers, broken or used parts, used packaging materials, and used air filters. These non-hazardous wastes will be routinely collected by a licensed hauler and disposed at a Class III landfill.		

Hazardous Operational Wastes	**MITIGATION**	**None**	**YES**
	Hazardous wastes will include recyclable materials such as used oil, filters, rags, etc. Non-recyclable hazardous wastes include oil absorbents, welding materials, paints, used grit, weak acids, used batteries, and asbestos and are properly disposed at Class I landfills. **MITIGATION:** ☑ The Project Owner shall prepare a waste management plan. Condition: **WASTE-5.** ☑ The Project Owner shall report any potential enforcement action related to waste management. Condition: **WASTE-4**. ☑ The Project Owner shall determine the appropriate disposal method for the ZLD salt cakes. Condition: **WASTE-7**.		
Disposal Capacity	**None**	**None**	**YES**
	The capacities of available Class I and Class III landfills far exceed the construction and operation wastes generated by this project.		

WASTE MANAGEMENT - GENERAL

Different types of wastes will be generated during the construction and operation of the proposed project and must be managed appropriately to minimize the potential for adverse human and environmental impacts. These wastes are designated as hazardous or non-hazardous according to the toxic nature of their respective constituents. This analysis assesses the adequacy of the waste management plan with respect to handling, storage and disposal of these wastes in the amounts estimated for the project.

Excavation

Greystone Environmental Consultants performed a Phase I Environmental Site Assessment (ESA) in June 2001 to document actual or potential environmental concerns at the BEP II site based on past and present uses of the site. It was performed in accordance with the guidelines of the American Society for Testing and Materials standard 1527 for Phase I ESAs. The Phase I ESA involved gathering information from historical records, aerial photographs, government and other sources, and a physical tour of the site with recordation of visual, olfactory and tactile perceptions. It was also supplemented with some limited soil sampling due to concerns regarding possible contamination in an area located on the northern boundary of the site. The Phase I ESA concluded the following:

- There is no evidence of any existing, past or threatened releases of contamination in connection with surrounding offsite properties that can impact the site.
- There is a former World War II era landfill located along the northern boundary of the site. Soil sampling along the northern boundary indicated an elevated level of lead at 570 parts per million (ppm) at one sampling location.

The concentration, however, is well below the U.S. Environmental Protection Agency (U.S. EPA) Region IX, Preliminary Remediation Goal (PRG) of 750 ppm for lead in soil permitted for industrial use. PRGs are chemical concentrations that correspond to fixed levels of health risk in soil, water, and air and serve as tools that can be used for evaluating and cleaning up contaminated sites. No additional sampling or remediation is therefore warranted at the site, as no adverse health effects are associated with the presence of lead. (FSA, p. 4.13-2-3)

Although the Phase I ESA did not identify onsite environmental concerns, subsurface contamination could be potentially encountered during earth moving activities. Depending on the nature and extent of contamination present, additional hazardous wastes may require transportation off-site to a permitted facility. (FSA, p. 4.13-4)

MITIGATION:

- ☑ The Project Owner and contractor, if necessary, will obtain a hazardous waste generator identification number. Condition: **WASTE-3**
- ☑ The Project Owner shall employ a registered engineer and prepare a waste management plan and a site remediation plan. Conditions: **WASTE-1** to **WASTE-5**
- ☑ Any contaminated soils will be tested and, if appropriate, treated or disposed at a Class I landfill. Conditions: **WASTE-2**

Construction Wastes

Preparation and construction of the power plant will generate both hazardous and non-hazardous wastes. The non-hazardous component of the construction-related wastes will include waste paper, wood, glass, scrap metal, plastics, packing materials, waste lumber, excess concrete, insulation materials, and non-hazardous chemical containers. Management of these wastes will be the responsibility of the contractors. These wastes will be segregated, where practical, for recycling. Those that cannot be recycled will be placed in covered containers and removed on a regular basis by a certified waste handling contractor for disposal at the Blythe Sanitary Landfill. (FSA, p. 4.13-3)

The relatively small quantities of hazardous materials to be generated during this construction phase will mainly consist of used oil, waste paint, spent solvents, materials, used batteries, and cleaning chemicals. These wastes will be recycled or disposed of at licensed hazardous waste treatment or disposal facilities. The construction contractor will be considered the generator of the hazardous waste produced during construction and will be responsible for compliance with applicable federal and state regulations regarding licensing, personnel training, accumulation limits, reporting requirements, and record keeping. (FSA, p. 4.13-4.)

MITIGATION:

- ☑ The Project Owner shall prepare a waste management plan to assure the appropriate handling of construction wastes. Condition: **WASTE-5**.
- ☑ The Project Owner and contractor, if necessary, will obtain a hazardous waste generator identification number. Condition: **WASTE-3**

Non-Hazardous Operational Wastes
Under normal operating conditions, the typical, solid non-hazardous wastes will include routine maintenance-related trash, office wastes, empty containers, broken or used parts, and used packaging materials and air filters. Some of the wastes will be recycled to minimize the quantity to be disposed of in a landfill. The non-recyclables will be disposed of at the Blythe Sanitary Landfill. The volume of non-hazardous wastes from the proposed facilities is estimated to be 65 cubic yards, which is readily accommodated within area disposal facilities. (FSA, p. 4.13-4)

Hazardous Operational Wastes
The hazardous waste quantities generated by the project will be minimal. The operations-related hazardous wastes will include spent air pollution control catalysts, used oil and air filters, used cleaning solvents, and used batteries. Many of these wastes will be recycled. The non-recyclables will be disposed of in a Class I disposal facility.

The Applicant recently elected to use a brine crystallizer zero liquid discharge (ZLD) process for wastewater, which will result in the creation of salt cakes requiring appropriate disposal. The Applicant will determine by testing whether the ZLD salt cakes are hazardous. Condition **WASTE-7**. (FSA, p. 4.13-4-5)

MITIGATION:
- ☑ The Project Owner shall prepare a waste management plan. Condition: **WASTE-5.**
- ☑ The Project Owner shall report any potential enforcement action related to waste management. Condition: **WASTE-4**.
- ☑ The Project Owner shall determine the appropriate disposal method for the ZLD salt cakes. Condition: **WASTE-7**.

Disposal Capacity
The Blythe Sanitary Landfill is a permitted class III (non-hazardous) facility about seven miles north of Blythe. It is projected to remain operational until 2073 and accepts an average daily load of about 50 tons/day. The volume of non-hazardous waste expected from constructing and operating BEP II is expected to be a fraction of one percent of the Blythe landfill's annual capacity. The total remaining capacity of the landfill is estimated to be five million cubic yards. Even discounting the effects of recycling on the total amount of non-hazardous wastes destined for landfill disposal, the amounts of waste generated during project construction and operation are insignificant relative to existing disposal capacity.

Three Class I landfills in California, at Kettleman Hills in King's County, Buttonwillow in Kern County, and Westmoreland in Imperial County, are permitted to accept hazardous waste. In total, there is in excess of twenty million cubic yards of remaining hazardous waste disposal capacity at these landfills, with remaining operating lifetimes of over 50 years. The amount of hazardous waste transported to these landfills has decreased in recent years due to source reduction efforts by generators, and the transport of waste out of state that is hazardous under California law, but not federal law.

Much of the hazardous waste generated during facility construction and operation will be recycled, such as used oil and spent catalysts. Even without recycling, the generation of hazardous waste from BEP II would be a very small fraction (less than one percent) of existing capacity and will not significantly impact the capacity or remaining life of any of the state's Class I landfills. (FSA, p. 4.13-5)

Cumulative Impacts

As described above, there is adequate capacity in the disposal facilities available with respect to the hazardous and non-hazardous wastes associated with the proposed project. Therefore, the wastes from the construction and operation of the proposed project and its related facilities will not significantly impact the capacity of these landfills and will not create a cumulative impact. (FSA, p. 4.13-6)

Finding

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to waste management and all potential adverse impacts related to waste management will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

WASTE-1 The project owner shall provide the resume of a California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer, who shall be responsible for oversight of earth moving activities requiring interpretation and proper application of geologic or engineering sciences to the CPM for review and approval. The resume shall show substantial experience in hazardous waste remedial investigation and feasibility studies.

The California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer shall be given full authority by the project owner to oversee and direct any earth moving activities that have the potential to disturb contaminated soil.

Verification: At least 30 days prior to the start of site mobilization the project owner shall submit the resume to the CPM.

WASTE-2 If potentially contaminated soil is unearthed during excavation at either the proposed site or linear facilities as evidenced by discoloration, odor, detection by handheld instruments, or other signs, the California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer or his authorized designee, shall, determine the need for sampling to confirm the nature and extent of contamination, and file a written report to the project owner and CPM stating the recommended course of action. All reports and proposals must be prepared by or under the direction of a registered professional as referenced above and signed and stamped (must include registration number and expiration date) by that professional.

Depending on the nature and extent of contamination, the California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer shall have the authority to temporarily suspend construction activity at that location for the protection of workers or the public. If, in the opinion of the California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer, significant remediation may be required, the project owner shall contact representatives of the Colorado River Basin Regional Water Quality Control Board, the Hazardous Materials Management Division of the Riverside County Department of Environmental Health, and the Cypress Regional Office of the California Department of Toxic Substances Control for guidance and possible oversight.

Verification: The project owner shall submit any reports or proposals filed by the California Registered Geologist, Certified Engineering Geologist, Certified Hydrogeologist or Professional Civil Engineer to the CPM within 5 days of their receipt. The project owner shall notify the CPM within 24 hours of any orders issued to halt construction.

WASTE-3 The project owner shall obtain a hazardous waste generator identification number from the Department of Toxic Substances Control or the U.S. Environmental Protection Agency prior to generating any hazardous waste.

Verification: The project owner shall keep its copy of the identification number on file at the project site and notify the CPM via the Monthly Compliance Report of its receipt.

WASTE-4 Upon becoming aware of any impending waste management-related enforcement action by any local, state, or federal authority, the project owner shall notify the CPM of any such 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 becoming aware of an impending enforcement action. The CPM shall notify the project owner of any changes that will be required in the manner in which project-related wastes are managed.

WASTE-5 The project owner shall prepare a Construction Waste Management Plan and an Operation Waste Management Plan for all wastes generated during construction and operation of the facility, respectively, and shall submit both plans to the CPM for review and approval. The plans shall contain, at a minimum, the following:

1. A description of all waste streams, including projections of frequency, amounts generated and hazard classifications; and

2. Methods of managing each waste, including treatment methods and companies contracted with for treatment services, waste testing methods to assure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/reduction plans.

<u>Verification:</u> No less than 30 days prior to the start of site mobilization, the project owner shall submit the Construction Waste Management Plan to the CPM. The operation waste management plan shall be submitted to the CPM no less than 30 days prior to the start of project operation. The project owner shall submit any required revisions within 20 days of notification by the CPM. In the Annual Compliance Reports, the project owner shall document the actual waste management methods used during the year compared to the planned management methods.

WASTE-6 Prior to any earth moving activities, employees involved in earth disturbance for construction purposes in previously undisturbed areas shall receive hazardous-waste-related training that focuses on the recognition of potentially contaminated soil and/or groundwater and contingency procedures to be followed as specified in WASTE-2 above. Training shall comply with Hazardous Waste Operations (8 CCR 5192) and Hazard Communication (8 CCR 5194) requirements as appropriate.

<u>Verification:</u> The project owner shall notify the CPM via the monthly compliance report of completion of the hazardous waste training program.

WASTE-7 The project owner shall determine if the ZLD generated wastes are hazardous or non-hazardous pursuant to Chapter 12, section 66262.11 of Title 22 of the California Code of Regulations. The wastes shall be managed as designated wastes if the wastes are classified as non-hazardous, unless determined otherwise.

<u>Verification:</u> The project owner shall notify the CPM via the annual compliance report regarding the classification of the wastes and the treatment/disposal methods utilized.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

WASTE MANAGEMENT

APPLICABLE LAW	DESCRIPTION
FEDERAL	
42 U.S.C. §§6901-6992k, RCRA Subtitle C and D	Regulates non-hazardous and hazardous wastes. Laws implemented by the State.
40 CFR 260, et seq.	Implements regulations for RCRA Subtitle C and D. Implemented by the US EPA by delegating to the State.
Federal Clean Water Act, 33 U.S.C. §1251 et seq.	Regulates wastewater discharges to surface waters of the US. NPDES program administered at the State level.
STATE	
Public Resources Code §40000 et seq. (California Integrated Waste Management Act)	Implements RCRA regulations for non-hazardous waste.
Water Code §13000, et seq. (Porter-Cologne Water Quality Control Act	Regulates wastewater discharges to surface and groundwater of California. NPDES program implemented by State Water Resources Control Board.
22 CCR §66262.34	Regulates accumulation periods for hazardous waste generators. Typically hazardous waste cannot be stored on-site for greater than 90 days.
Health & Safety Code §25100 et seq. (California Hazardous Waste Control Law)	Regulates hazardous waste handling/storing.
14 CCR §17200, et seq.	Establish standards for solid waste handling and disposal.
LOCAL	
None	

WATER QUALITY & SOILS – Summary of Findings and Conditions

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Drainage, Erosion &, Sedimentation	**MITIGATION**	**None**	**Yes**
	Grading and excavation may create the potential for transport of loosened soils by wind, rainwater or on-site release of fluids. Applicant proposes to control fugitive dust emissions during construction. The Applicant will also prepare a Drainage, Erosion and Sedimentation Control Plan that will include provisions for dust control during construction and operation. Post-construction maintenance will include the use of Best Management Practices to control wind erosion. The project is located within the 152 acre BEP complex that is largely paved and equipped with drainage gutters and catch basins to collect stormwater runoff. All runoff that has not contacted oily or possibly contaminated plant surfaces will be routed directly by drainage channels to the existing retention basin serving BEP. "Contact" runoff, which may be contaminated from plant process areas, will be routed to the oil-water separator and then to the evaporation pond. The retention basin has sufficient capacity for a 100-year storm so long as accumulated sediments are removed periodically. **MITIGATION:** ☑ The project owner shall comply with a construction NPDES permit, if required. Condition: **WATER QUALITY-1** ☑ The project owner shall prepare a Drainage, Erosion and Sedimentation Control Plans to contain and process runoff on-site and to prevent or contain any spill or leak of construction materials onto soils or into runoff waters. Conditions: **WATER QUALITY-2** ☑ The project owner shall comply with an operation NPDES permit and develop a SWPPP for the operational phase of the project. Condition: **WATER QUALITY-3** ☑ To control airborne fugitive dust, the project owner shall water disturbed areas and apply chemical dust suppressants, apply gravel or paving to traffic areas, wash wheels of vehicles of large trucks leaving the site. Condition: **AQ-C2**		

	POWER PLANT SITE	*CUMULATIVE IMPACTS*	*LORS COMPLIANCE*
Prior Contamination: Soil or Water	**MITIGATION**	**None**	**Yes**
	Although the Phase I ESA did not identify onsite environmental concerns, subsurface contamination could be potentially encountered during earth moving activities. Depending on the nature and extent of contamination present, additional hazardous wastes may require transportation off-site to a permitted facility. Impacts may be produced from chemical constituents detected in groundwater from an old mobile home well on the BEP I property that would be concentrated and released as a mist from the cooling towers. BEP II groundwater will be tested to verify that there are no significant sources of groundwater contamination. **MITIGATION:** ☑ Any contaminated soils will be tested and, if appropriate, treated or disposed at a Class I landfill. Conditions: **WASTE-2** ☑ The project owner shall conduct an annual groundwater quality sampling and analysis of groundwater. Condition: **WATER QUALITY-6**.		
Wastewater	**MITIGATION**	**None**	**Yes**
	Wastewater will be generated at the plant in various systems, mostly cooling tower blowdown. The Applicant amended the project to substitute a zero-liquid-discharge (ZLD) system utilizing brine crystallization technology. The initially proposed evaporation ponds will not be used, except for shutdown or maintenance of the brine crystallizer. The ZLD system produces salt "cakes" that will be tested for hazardous materials and disposed of in a licensed landfill. (See Condition **WASTE-7**) Sanitary wastewater will be managed and discharged via an on-site septic system and drain field to be designed according to applicable City and County laws. **MITIGATION:** ☑ The project will use a Zero Liquid Discharge system for the treatment of wastewaters. Condition: **WATER QUALITY-5.** ☑ The project owner shall install an on-site septic system for domestic wastewater. Condition: **WATER QUALITY-4**.		

WATER QUALITY – GENERAL

This section analyzes potential effects on water quality and soil resources that could result from construction and operation of the project, specifically focusing on the potential for erosion and sedimentation and degradation of surface and groundwater quality. For most of the Staff review period of the project, the Applicant was going to employ an evaporation pond as its primary means to dispose of project wastewaters. Prior to evidentiary hearings, the Applicant revised its project to include the Staff-suggested Zero Liquid Discharge process using a brine crystallizer. The planned evaporation pond would be used only when that equipment is not available.

Flooding is addressed in the **GEOLOGY** section of this decision. Solid waste and contaminated soil disposal is discussed in the **WASTE MANAGEMENT** section.

<u>Drainage, Erosion & Sedimentation</u>

Earthmoving activities associated with construction of the proposed project can expose and disturb the soil, leaving soil particles vulnerable to being blown into the air or to being moved by rainwater or spilled liquids. Stormwater runoff, coupled with earth disturbance activities, can potentially cause onsite erosion, potentially resulting in off-site erosion and sedimentation possibly impacting surface waters.

Soils in the region are primarily derived from alluvial and colluvial deposits and range from coarse to moderately fine in texture. On the Palo Verde Mesa, soils tend to be well to excessively drained, coarse grained, sands, gravels and loam with relatively low erosion hazards. The soils at the site are primarily made up of four soil types with textures ranging from moderately fine to coarse. The water erosion hazard is expected to be slight at the BEP site and along the transmission lines. The wind erosion potential for most of these soils is moderate to high. (FSA, pp. 4.9-5-7

<u>Wind – Construction & Operation</u>

As discussed in detail in the **AIR QUALITY** section, the Applicant propose to control fugitive dust emissions during construction with the following measures:

- Use water application or chemical dust suppressant on unpaved travel surfaces and parking areas.
- Use wetting or covering of stored earth materials on-site.
- Require all trucks hauling loose material to either cover or maintain a minimum of two feet of freeboard.
- Use gravel pads and wheel washers as needed.
- Use windbreaks and chemical dust suppressant or water application to control wind erosion from disturbed areas.

If the mitigation measures for fugitive dust-generating activities are applied correctly and with sufficient frequency, the control efficiency can approach 100 percent. The effectiveness of the mitigation measures depends upon the vigilance of construction personnel. See Conditions: **AQ-C3 & AQ-C4.**

The Applicant will also prepare a Drainage, Erosion and Sedimentation Control Plan that will include provisions for dust control during construction and operation. Post-construction maintenance will include the use of Best Management Practices to control wind erosion.

Stormwater – Construction & Operation
The project is located within a currently developed power generating complex that is largely paved and equipped with drainage gutters and catch basins to collect stormwater runoff. The relatively flat topography at the site naturally drains towards the southeast. Uphill from the site is an approximately 1,134-acre watershed, which will cause runoff onto the site that will be routed in drainage channels to the retention basin in the southern portion of the BEP site. The BEP II site is not located near any natural surface water features and is not within a 100-year floodplain.

During operation, all runoff on the 152 acre BEP site, which has not contacted oily or possibly contaminated plant surfaces, will be routed directly by a network of drainage channels and culverts to the retention basin. The retention basin served both BEP I and BEP II. “Contact” runoff, which may be contaminated from plant process areas, will be routed to the oil-water separator and then to the evaporation pond.

The retention basin is intended to capture and percolate all runoff generated by a 100-year 24-hour event and to prevent potential storm water drainage impacts. Retention basin design plans submitted by BEP were reviewed and approved by the City of Blythe, the Blythe Chief Building Officer (CBO), and the Energy Commission during licensing phase of BEP I. With the stormwater control systems in place, the BEP II project may not need a General National Pollution Discharge Elimination System (NPDES) construction permit, since the project would not impact off-site waters. (FSA, pp. 4.9-19, 25 & 29)

Staff questioned whether operational plans were necessary for the retention basis to assure that it would retain the capacity to handle the 100-year storm. Storm drainage calculations from BEP I indicated that the retention basin could store up to 3.5 feet (24.25 acre-feet) of eroded sediment and be minimally capable of handling the 100-year storm with minimum percolation rates. (FSA, p. 4.9-47, 48) Staff prepared a proposed condition of certification to require frequent removal of accumulated sediments. Following discussions between the Applicant and Staff, the parties agreed that BEP II would monitor accumulated sediment levels as part of its Drainage, Erosion, and Sediment Control Plan, and that removal of accumulated sediments in the retention basin is the responsibility of the BEP I project owner. (8/2/05 RT 4:18 – 5:4)

As required by Colorado River Basin Regional Water Quality Control Board (RWQCB), the Applicant will implement a Stormwater Pollution Prevention Plan (SWPPP) to minimize erosion from both construction and operation activities.

CONDITIONS:

- ☑ The project owner shall comply with a construction NPDES permit, if required. Condition: **WATER QUALITY-1**
- ☑ The project owner shall prepare a Drainage, Erosion and Sedimentation Control Plans to contain and process runoff on-site and to prevent or contain any spill or leak of construction materials onto soils or into runoff waters. Conditions: **WATER QUALITY-2**
- ☑ The project owner shall comply with an operation NPDES permit and develop a SWPPP for the operational phase of the project. Condition: **WATER QUALITY-3**

- ☑ To control airborne fugitive dust, the project owner shall water disturbed areas and apply chemical dust suppressants, apply gravel or paving to traffic areas, wash wheels of vehicles of large trucks leaving the site. Condition: **AQ-C2**

Prior Soil Contamination

Although the Phase I ESA did not identify onsite environmental concerns, subsurface contamination could be potentially encountered during earth moving activities. Depending on the nature and extent of contamination present, additional hazardous wastes may require transportation off-site to a permitted facility. (FSA, p. 4.13-4)

CONDITION:

- ☑ Any contaminated soils will be tested and, if appropriate, treated or disposed at a Class I landfill. Conditions: **WASTE-2**

Groundwater Quality

Staff identified three potential adverse impacts related to groundwater quality that could be caused by the proposed project. Impacts may be produced from chemical constituents in groundwater that would be concentrated and released as a mist from the cooling towers. The hazardous chemicals detected in groundwater from an old mobile home well on the BEP I property could be in groundwater from the BEP II wells, given the proximity of the project wells to BEP I. BEP I was required to test groundwater samples annually for five years. To date, testing has not found any volatile or non-volatile organic compounds. BEP II groundwater will be similarly tested to verify that there are no significant sources of groundwater contamination. (FSA, pp. 4.9-36, 37)

Theoretically, project groundwater pumping could cause hazardous chemicals already in the saturated soils to move and thus impact the project wells or in existing private wells. The Applicant's contaminant investigation did not identify any significant unmitigated contamination sites near the project. Staff agrees there is no evidence of an unmitigated source of groundwater contamination, and thus no potential for significant impact. (FSA, p. 4.9-36, 37)

The potential for upwelling of saline waters resulting from project pumping is discussed in the **WATER RESOURCES** section.

The Applicant has recommended the adoption of the BEP I Condition of Certification, which requires annual analyses of groundwater samples from on-site wells and reassessment of treatment requirements if significant changes in groundwater quality occur to ensure impacts remain less than significant. (FSA, p.4.9-58) Staff recommends a revised version of the BEP I Condition that will identify the chemicals to be sampled, define what constitutes a "significant increase in contamination" to be tested, and specify further actions if significant increased contamination is found. (Staff Opening Brief, p. 26) The Commission believes that an updated groundwater sampling Condition is appropriate.

CONDITION:

- ☑ The project owner shall conduct an annual groundwater quality sampling and analysis of groundwater. Condition: **WATER QUALITY-6**.

Wastewater

By far, the largest amount of wastewater comes from the cooling process. The water from the on-site wells is directed to the cooling tower, where it goes through 7 cycles of concentration. A portion of the concentrated water, called "blowdown" is sent from the cooling towers to a brine concentrator system. As originally proposed, the blowdown is flashed off in a vacuum system, with pure water being returned to plant uses and the remaining 5 percent, containing essentially all the dissolved solids, sent to an evaporation pond. The wastewater sent to the evaporation ponds would accurately be described as brine, and is far "saltier" than ocean water.

To avoid potential biological impacts from the evaporation ponds, the Applicant amended the project to substitute a zero-liquid-discharge (ZLD) system utilizing brine crystallization technology. Thus, the initially proposed evaporation ponds will not be used, except for shutdown or maintenance of the brine crystallizer. The ZLD system produces salt "cakes" that will be tested for hazardous materials and disposed of in a licensed landfill. (See Condition **WASTE-7**) Consequently, with the ZLD system, project wastewaters will not cause a significant impact.

Sanitary wastewater will be managed and discharged via an on-site septic system and drain field to be designed according to applicable City and County laws. (FSA, p. 4.9-46

MITIGATION:

- ☑ The project will use a Zero Liquid Discharge system for the treatment of wastewaters. Condition: **WATER QUALITY-5.**
- ☑ The project owner shall install an on-site septic system for domestic wastewater. Condition: **WATER QUALITY-4**.

Cumulative Impacts

No other projects are proposed in the vicinity of the power plant and, thus, the project will not result in any cumulative environmental impacts from construction or operational activities.

Findings

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to water quality and all potential water quality impacts will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

NPDES PERMIT (CONSTRUCTION)

WATER QUALITY - 1: The project owner shall comply with the requirements of the General National Pollutant Discharge Elimination System (NPDES) Permit for Discharges of Storm Water Associated with Construction Activity, if necessary. The project owner shall develop and implement a Storm Water Pollution Prevention Plan for the construction of the entire Blythe Energy Project II (BEP II) project (construction SWPPP).

Verification: The project owner shall submit copies to the CPM of all correspondence between the project owner and the RWQCB about the General NPDES permit for the Discharge of Storm Water Associated with Construction Activities within 10 days of its receipt (when the project owner receives correspondence from the RWQCB) or within 10 days of its mailing (when the project owner sends correspondence to the RWQCB). This information shall include copies of the Notice of Intent and Notice of Termination for the project.

DRAINAGE, EROSION AND SEDIMENTATION CONTROL PLAN

WATER QUALITY - 2: Prior to site mobilization, the project owner shall obtain CPM approval for a site-specific Drainage, Erosion and Sedimentation Control Plan (DESCP) that ensures protection of water quality and soil resources of the project site and all linear facilities for both the construction and operations 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, meet local requirements, and identify all monitoring and maintenance activities. Monitoring activities shall include routine measurement of the volume of accumulated sediment in the stormwater retention basin. The plan shall be consistent with the grading and drainage plan as required by Condition **CIVIL-1** and may incorporate by reference any SWPPP developed in conjunction with any NPDES permit. The DESCP shall contain the following elements:

Vicinity Map – A map shall be provided indicating the location of all project elements with depiction of significant geographic features to include watercourses, washes, irrigation and drainage canals, and sensitive areas.

Site Delineation – The BEP II site and all project elements shall be delineated showing boundary lines of all construction areas and the location of existing and proposed structures, pipelines, roads, and drainage facilities.

Watercourses and Critical Areas – The DESCP shall show the location of nearby watercourses including washes, irrigation and drainage canals, and drainage ditches. Indicate the proximity of those features to the BEP II construction site and all pipeline and transmission line construction corridors.

Drainage – The DESCP shall provide a topographic site map showing existing, interim and proposed drainage systems; drainage area boundaries and water shed sizes in acres; the hydraulic analysis to support the selection of BMPs to divert off-site drainage around or through the site and laydown areas. On the map, spot elevations are required where relatively flat conditions exist. The spot elevations and contours shall be extended off-site for a minimum distance of 100 feet in flat terrain.

Clearing and Grading – The plan shall provide a delineation of areas to be cleared of vegetation and areas to be preserved. The plan shall provide elevations, slope, location, and extent of all proposed grading as shown by contours, cross sections or other means. The locations of any disposal areas, fills, or other special features will also be shown. Illustrate existing and proposed topography tying in proposed contours with existing topography. The DESCP shall include a statement of the quantities of material excavated or filled for each element of the BEP II (project site, transmission corridors, and pipeline corridors), whether such excavations or fill is temporary or permanent, and the amount of such material to be imported or exported.

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 excavation and construction, and final grading/stabilization). 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, final grading/stabilization, and following construction. BMPs shall include measures designed to control dust and stabilize construction access roads and entrances. The maintenance schedule should include post-construction maintenance of treatment control BMPs applied to disturbed areas following construction.

Erosion Control Drawings -- The erosion control drawings and narrative must be designed and sealed by a professional engineer/erosion control specialist.

Verification: No later than 60 days prior to start of site mobilization, the project owner shall submit a copy of the plan to Riverside County and the City of Blythe for review and comment, and to the CPM for review and approval. The CPM shall consider comments received from Riverside County and the City of Blythe. 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. Once operational, the project owner shall provide in the annual compliance report information on the results of monitoring and maintenance activities.

NPDES PERMIT (OPERATION)

WATER QUALITY - 3: 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 and implement a Storm Water Pollution Prevention Plan for the operation of the BEP II site (operation SWPPP).

Verification: The project owner shall submit copies to the CPM of the operational SWPPP for the entire BEP II site prior to commercial operation and all correspondence between the project owner and the RWQCB about the General NPDES permit for Discharge of Storm Water Associated with Industrial Activity within 10 days of its receipt (when the project owner receives correspondence from the RWQCB) or within 10 days of its mailing (when the project owner sends correspondence to the RWQCB). This information shall include a copy of the Notice of Intent and Notice of Termination. A letter from the RWQCB indicating no General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity is required will satisfy this condition.

SEPTIC SYSTEM

WATER QUALITY - 4: The on-site septic system shall be designed and operated to comply with County and City standards and prevent any adverse impacts to water quality. Prior to the start of commercial operation and/or discharge of waste to the septic system, the project owner shall provide the CPM with documentation from Riverside County and the City of Blythe confirming that the septic system design and operational plan is consistent with County and City standards. Waste shall not be discharged to the septic system until the documentation confirming that the system design and operating plan are consistent with County and City standards has been reviewed and approved by the CPM.

Verification: No later than sixty days prior to start of commercial operation and/or discharge of waste to the septic system the project owner shall submit the required documentation from the County and City to the CPM for review and approval.

ZERO LIQUID DISCHARGE SYSTEM

WATER QUALITY - 5: The project shall operate with a Zero Liquid Discharge (ZLD) wastewater treatment system. A liquid wastewater discharge either on or off-site is prohibited, with the exception of the temporary discharge of wastewater to evaporation ponds permitted by the RWQCB via the issuance of Waste Discharge Requirements during periods of ZLD system outages. The design shall include a schematic, narrative of operation, maintenance schedules, on-site salt cake or slurry storage facilities, containment measures and influent water quality. The design information shall also include characterization of the residual cake solid or slurry waste to be produced by the ZLD system that adequately describes the physical and chemical properties for consideration of appropriate storage, transportation, and disposal. The project owner shall provide annual reporting of the functionality of the ZLD system and document any problems to the CPM.

Verification: Sixty (60) days prior to the start of construction of the Zero Liquid Discharge (ZLD) system, the project owner shall submit to the CPM the final design of the system for approval. In the annual compliance report, the project owner shall submit a status report on operation of the ZLD system, including disruptions, maintenance, volumes of interim wastewater streams stored on site, volumes of residual cake solids or slurry generated and the landfills used for disposal.

GROUNDWATER TESTING

WATER QUALITY - 6: The Applicant shall conduct an annual water quality sampling and analysis of groundwater from any one of the operational wells constructed to supply the project with groundwater and report the results of the analysis to the CPM. The report shall include a summary table that, at a minimum, lists for each of the constituents analyzed, the name of the constituent, the unit of measurement, the method, the applicable standard, the detection level, the sample results, the date sampled and the date analyzed. The report shall also include copies of the original laboratory reports.

Water quality sampling shall include the analysis of the following constituents:

Constituents	Constituents (continued)	Constituents (continued)
Total Hardness	Cyanide	Total Organic Carbon
Calcium	Foaming Agents (MBAs)	Aluminum
Calcium as Calcium Carbonate	Phenols	Antimony
Magnesium	Ortho Phosphate Phosphorus	Arsenic
Total Alkalinity	Kjeldahl Nitrogen	Barium
Hydroxide	Total Nitrogen	Lead
Carbonate Bicarbonate	Boron	Cadmium
pH	Hexavalent Chromium	Copper
Total Dissolved Solids	Manganese	Iron
Langelier Index	Reactive Silica	Mercury
Glyphosate	Total Silica	Nickel
Triazine Pesticides	Tin	Selenium
Chlorothalonils	Carbon Dioxide	Strontium
Chlorinated Herbicides and Bentazon	Nitrate – Nitrogen	Zinc
Ethylebenzene	Nitrite – Nitrogen	Odor
Toluene	Fluoride	Aggressive Index
Total Zylenes	Specific Conductance	Sulfate
1,4-Dichlorobenzene	Total Cations	Chloride
Methylene Chloride	Total Anions	Potassium
Styrene	Total Suspended Solids	Silver
Di (2 Ethyl Hexyl) Adipate, Benzo (a) Pyrene, and Di (2 Ethyl Hexyl) Phthalate	Biochemical Oxygen Demand	Thallium
Dibromochloropropane and Ethylene Dibromide	Oil and Grease	Coliform
Carbamate Pesticides	Total Phosphorus	Gross Alpha
Sodium	Color	2,3,7,8-TCDD (Tetrachlorodibenzo-P-Dioxin)
Ammonia-Nitrogen	Turbidity	Diquat

Appropriate sampling and analytical quality assurance and quality control documentation from the laboratory of choice shall be included with the analytical results.

The results of the required groundwater analyses shall be provided to the CPM and the Colorado River Basin Regional Water Quality Control Board, including a summary and a complete copy of the analytical laboratory reports, on an annual basis beginning after one year of operation on the anniversary date the BEP II begins operation and continuing for a total of 5-years. If no annual analyses during the first five years of the project indicate that the concentration of any contaminant found in groundwater is above its ESL, the need for continued monitoring shall be reassessed at the end of the 5-year period, and the monitoring program shall be modified as appropriate by the CPM.

If any annual analysis indicates that the concentration of any contaminant found in groundwater is above its Environmental Screening Level (ESL as determined by the San Francisco Bay Regional Water Quality Control Board), the project owner shall be required to develop a mitigation workplan for one of the mitigation options. The workplan shall be submitted to the Colorado River Basin Regional Water Quality Control Board for review and comment and to the CPM for review and approval. Based on discussions between the CPM, the project owner, and the Colorado River Basin Regional Water Quality Control Board, the CPM will direct the project owner to prepare:

a. A human health risk assessment, using methodology reviewed by the Colorado River Basin Regional Water Quality Control Board and approved by the CPM, demonstrating that the increased level(s) of groundwater contaminant(s) pose an insignificant risk to on-site workers and the off-site public, or
b. A pre-treatment plan for groundwater to reduce the contaminant levels to below the applicable ESL.

If the risk assessment is approved by the CPM, groundwater shall continued to be used for the project and the workplan shall provide for annual groundwater sampling, additional risk assessment as required by the CPM, and reporting for the life of the project to demonstrate that the level(s) of groundwater contaminant(s) continue to pose an insignificant risk to on-site workers and the off-site public. However, if subsequent risk assessments indicate a significant risk to on-site workers or the off-site public, a new mitigation workplan shall be required and the project owner shall be required to implement a pre-treatment plan for groundwater.

If a pre-treatment plan is selected and treated groundwater is used for the project, the workplan shall include quarterly sampling, analysis, and reporting to verify that groundwater treatment is effective and all constituent concentrations of the project water supply remain below the applicable ESL. Should the initial treatment method be determined ineffective at maintaining contaminant levels below the applicable ESL, a new workplan shall be required and the project owner shall be required to implement modify the water treatment method. If no treatment method is capable of maintaining contaminant levels below the applicable ESL, the CPM shall report the matter to the Commission.

Verification: If any annual analysis indicates that the concentration of any contaminant found in groundwater is above its ESL, the required mitigation workplan shall be submitted to the CPM for review and approval with 90 days of the submittal of the annual water quality sampling and analysis report.

WATER QUALITY - 7: The project owner shall comply with all of the requirements of the RWQCB to discharge wastewater to the project's evaporation ponds. The project owner shall follow RWQCB Waste Discharge Requirements (WDRs) for these ponds, and shall not discharge any waste to the evaporation ponds without final WDRs in place. The project owner shall report to the CPM any notice of violation, cease and desist order, cleanup and abatement order, or other enforcement action taken by the RWQCB related to the WDRs.

The project owner shall describe all actions taken to correct violations and operate the project in compliance with WDRs permit conditions. The project owner shall provide confirmation from the RWCQB that any violations have been resolved to the satisfaction of the RWQCB.

<u>Verification</u>: Final RWQCB WDRs must be received by the CPM prior to start of commercial operation and/or discharge of waste to the ponds. The project owner shall report violations and the final resolution of the violation within 10 days of notice by the RWQCB.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

WATER QUALITY & SOILS

APPLICABLE LAW	DESCRIPTION
FEDERAL	
Clean Water Act; 33 U.S.C. §1251 et seq.	Regulates discharges of wastewater and stormwater. Applies to wastewater discharged from cooling tower basins and stormwater runoff. These discharges are subject to NPDES permits obtained through the RWQCB at the state level.
STATE	
Porter Cologne Water Quality Control Act, Water Code §13000 et seq.	Established jurisdiction of nine RWQCBs to control pollutant discharges to surface and groundwater.
SWRCB Water Quality Order Nos. 91-13-DWQ and 92-08-DWQ	Regulates industrial stormwater discharges during construction and operation. These discharges subject to NPDES permits obtained through the RWQCB.
Safe Drinking Water and Toxic Enforcement Act (Prop. 65)	Prohibits the discharge of any substance known to cause cancer or birth defects to sources of drinking water.
LOCAL	
RWQCB	Responsible for controlling water quality.

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WATER RESOURCES – Summary of Findings and Conditions

	POWER PLANT SITE	CUMULATIVE IMPACTS	LORS COMPLIANCE
Water Supply Policy	**CONDITION**	**NONE**	**YES**
	The project would obtain its water supply from two wells providing 3,300 acre-feet of groundwater annually, mostly for cooling, from the Palo Verde Mesa aquifer. Historically, the aquifer was charged by Colorado River flooding and is now recharged by percolating irrigation water diverted from the River. The United States Bureau of Reclamation (USBR) has primary jurisdiction over use of Colorado River surface waters, but does not currently regulate groundwater withdrawals from aquifers recharged by diverted River water. Project groundwater is marginally brackish and so does not readily conform to California Water Policy on waters for power plant cooling. Local municipal wastewater supplies are insufficient for project operation. Local post-irrigation drain water to be returned to the River contains mostly fresh water, which is highly disfavored for power plant cooling, and its use would immediately decrease supplies available to downstream water users. Dry cooling in the hot desert does not offer the operating flexibility to reliably operate the project as the type of facility likely to be in greatest demand in today's electricity marketplace. Additionally, dry cooling costs significantly more than wet cooling and produces more hazardous thermal plumes in this Blythe Airport environment. The Applicant has proposed a voluntary Water Conservation Offset Program (WCOP) to offset its annual groundwater water use by fallowing or retiring irrigated farmlands in anticipation of the USBR's potential regulation of groundwater use. To avoid potential environmental impacts, the WCOP needs to include measures to protect from erosion and to verify true water conservation from qualifying farmlands. Potential upwelling of deep saline waters due to the project wells' depth and pumping rates will not adversely affect existing nearby wells or future wells which need not be drilled so deeply. **CONDITIONS:** ☑ To ensure no adverse environmental impacts, the WCOP shall include a comprehensive set of anti-erosion measures, criteria for farmlands eligible for the Program, and appropriate monitoring of verifiable water conservation. Condition: **WATER RES-1** ☑ The project owner shall install metering devices to record the daily amount of groundwater withdrawn by BEP II. Condition: **WATER RES - 2**		

Well Interference	**NONE** / **MITIGATION** / **YES** The project-induced drawdown of the aquifer is expected to be about five feet; consequently any interference with existing wells can be mitigated by restoring pumping capabilities to pre-project levels. **MITIGATION:** ☑ If project groundwater pumping interferes with existing nearby wells, the Project Owner shall undertake measures to restore their pumping capability to pre-project levels. Condition: **WATER RES-3.**

WATER RESOURCES – GENERAL

BEP II's proposed water supply for all plant uses would be from two 3,300 gallons per minute (gpm) groundwater wells to be constructed on the BEP II site. The wells would reach a depth between 500 – 600 feet. These wells would be in addition to the two wells constructed for BEP I. The Applicant has proposed to interconnect the water delivery system of BEP II with BEP I to provide operational flexibility. Each of the project wells on both sites is designed to independently meet the project water requirements. The BEP I and BEP II project's combined groundwater use would be 6,600 acre-feet/year. The second well on each site is designed to provide backup to the first well. However, during emergencies, both wells on a single site could provide the entire water supply to both projects because the systems would be interconnected and all wells would have similar capacities as the BEP I. The Applicant states that BEP II would limit emergency pumping to a few days.

Water use requirements include makeup for the cooling tower, demineralized water for the steam system, and potable water. The minimum, average and maximum rates of water usage for BEP II are estimated to be about 1,670, 2,200 and 3,000 gpm, respectively. Annual consumption of water is expected not to exceed 3,300 acre-feet per year. Actual water use will vary with power output, ambient temperature, duct firing, and humidity. Maximum water consumption coincides with maximum generator output and is achieved in a combined cycle plant when auxiliary duct burners are operating. (FSA, pp. 4.9-21-22)

The BEP I Decision on Water Resources

In the BEP I proceedings, the Commission faced the same issues regarding Water Resources for BEP II. The Applicant proposed to use well water for project cooling and asserted that the groundwater was sufficiently brackish to conform to State water policy for power plant cooling. Even though the Bureau of Reclamation, the federal agency with jurisdiction over Colorado River water, has not regulated wells in aquifers recharged by the River, the BEP I Applicant proposed a voluntary Water Conservation Offset Program (WCOP) to fallow irrigated farmland to offset the power plant's water usage.

Energy Commission staff characterized the groundwater from the BEP I wells as Colorado River water; thus, project pumping would be an unallocated and impermissible use. Staff also claimed that the groundwater was not sufficiently brackish and so should be considered as fresh water, which is the most disfavored source for cooling water. Staff suggested that the BEP I project use dry cooling as an alternative to the use of groundwater.

In its Decision, the Commission stated:

> . . . [R]easonable alternative sources of water for project cooling are not available or of sufficient quantities. Furthermore, the use of alternative cooling technologies would cost more that the proposed use of wet cooling. Therefore, we conclude that the project complies with the SWRCB Policy 75-58, whether it applies of not.
>
> It is important to note that BEP is not using “fresh” water for cooling purposes in its strictest sense. The quality of the groundwater to be used is very poor as it is high in Total Dissolved Solids (TDS). Applicant recognizes this and listed the poor water quality as one of the reasons the project site was selected. Staff also found the quality to be poor, although they declined to use the word “brackish.” The appropriate inquiry on this project is not whether the applicant *could* use an alternative cooling technology, but whether it *must*. The use of a dry or hybrid wet/dry cooling system at BEP is technically feasible but is not necessary to reduce any direct, indirect, or cumulative environmental impacts to below a level of significance. SWRCB Policy 75-58 is not a prohibition on the use of inland waters but rather direction on consideration of cooling alternatives, particularly when projects have the potential to cause significant adverse impact. After review of alternative cooling technologies and their associated costs and benefits, and consideration of the lack of any potentially significant adverse impacts associated with BEP’s proposed use of resources, we conclude that the water supply as proposed by the applicant is acceptable.
>
> The Commission continues to be concerned over the use of fresh water, a scarce resource in California, for power plant cooling purposes. The poor quality of the groundwater BEP will be using mitigates some of the concerns on this issue for this particular project…
>
> ….
>
> The need for a Water Conservation Offset Program is not driven by a finding of adverse environmental impact, or need to mitigate under the existing LORS. Therefore, the WCOP, in this case, is sufficient to satisfy the Commission’s concerns. (Commission Decision, Blythe Energy Project, p. 207)

The BEP II Applicant contended that the BEP I Decision essentially disposed of all BEP II issues as well. Staff argued that the Commission was not bound to its prior Decision and that there was new information that warranted further hearing. The Commission developed an extensive record dealing with all water resource issues.

California Water Policy
The California State Water Resources Control Board specifically addresses the siting of energy facilities in its *Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Powerplant Cooling* (adopted by the Board on June 19, 1975 as Resolution 75-58). This policy states that 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. This SWRCB policy requires that power plant cooling water should come from, in order of priority: wastewater being discharged to the ocean, ocean water, brackish water from natural sources or irrigation return flow, inland waste waters of low total dissolved solids, and other inland waters.

The California Energy Commission adopted its 2003 Integrated Energy Policy Report; Section 5 discusses power plant water use, as follows in relevant part:

> Water conservation is of paramount importance to the state. Indeed, conserving fresh water and avoiding its wasteful use have long been a 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 states water resources.
>
> *State water policy* regarding power plants is specified in Resolution 75-58 adopted by the State Water Resources Control Board. …… Consistent with the Board policy and the Warren-Alquist Act, the Energy Commission will approve the use of fresh water for cooling purposes by power plants which it licenses only where alternative cooling technologies are shown to be "environmentally undesirable" or "economically unsound." (Emphasis added; 2003 IEPR, pp, 40-41)

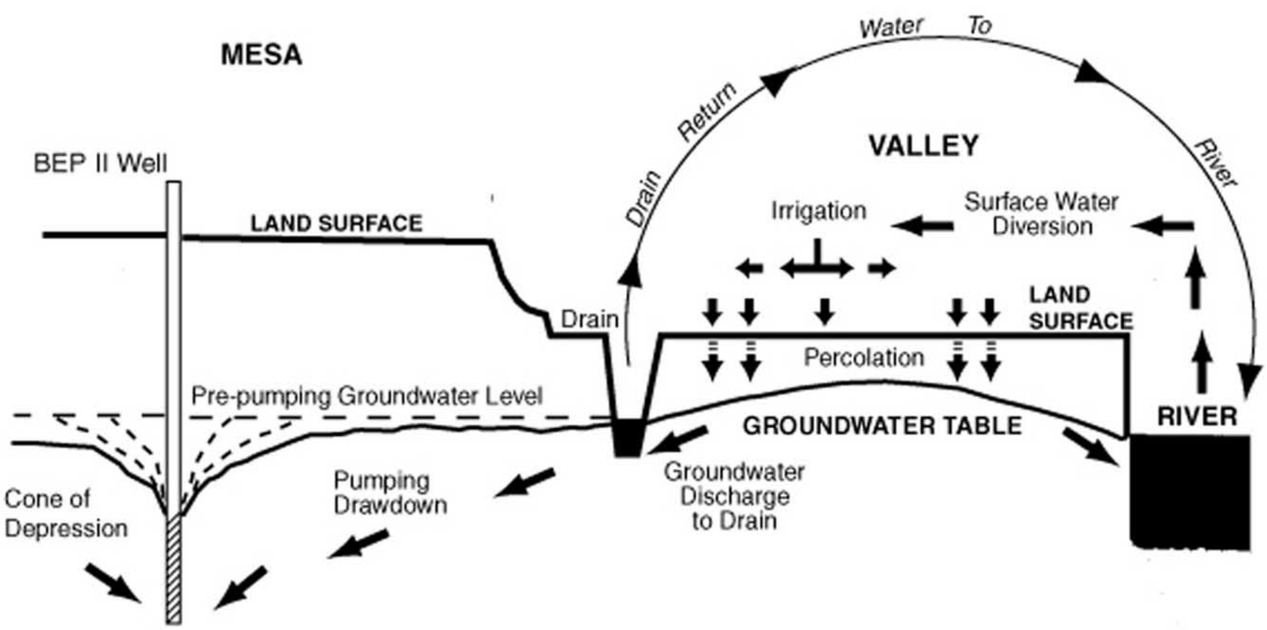
The Commission views Section 5 of the 2003 IEPR as a restatement of *existing* State water policy. We did not create new, substantive water policy in the 2003 IEPR. Rather, Section 5 reiterates a steadfast promise to current and future Californians that we will protect this most precious resource. Moreover, it is a strong admonition to power plant developers that water conservation must be a high priority in planning future projects.

The Hydrologic Cycle
The Colorado River is the source of virtually all of the water in the Palo Verde groundwater system. Water stored in the aquifer, as well as ongoing recharge to the aquifer, is derived primarily from Colorado River water.

Prior to the arrival of man, water from the Colorado River filled the valley sediments through lateral underground flow from the river channel and from percolation to the groundwater system during periodic overbank flooding. Following the construction of the dams and the advent of agriculture, overland flooding of the Colorado River to recharge the groundwater has been replaced by irrigation with Colorado River water diverted to the valley and mesa for agricultural production. Although the natural process of overland flooding has been replaced by diversions and irrigation, the Colorado River continues to be the only significant source of recharge to the aquifers.

In fact, irrigation with Colorado River water has raised groundwater levels in the Palo Verde Valley above historical levels. The amount of groundwater recharge from irrigation has so soaked the soil and raised the water table that a network of drainage ditches has been constructed throughout the valley to remove percolating irrigation water that would otherwise “flood” the root zones of the crops. Irrigation with Palo Verde Irrigation District’s (PVID) Colorado River diversions and its network of drainage ditches maintain constant groundwater water levels a few feet below land surface throughout the Palo Verde Valley. Under these conditions, the groundwater system is hydraulically connected to the irrigation drains and unlined canals.

Given the constant supply of percolating irrigation water and the interconnectivity of the aquifer system, groundwater recharge increases whenever groundwater pumping increases in the Palo Verde Valley or the Palo Verde Mesa. Correspondingly, increases in groundwater recharge cause decreases in irrigation drain discharge and return flows to the Colorado River. (FSA, pp. 4.9-9-10)



Groundwater pumping forms a cone of depression that radiates from each active well, creating groundwater gradients towards the well. Initially, the well produces water that is stored in the aquifer within the cone of depression. However, in the long-term, groundwater production is sustained by the lateral flow of water to the well. Drawdown of stored aquifer water stabilizes when the cone of depression intercepts a source of recharge water and induces flow toward the pumping well. Finally, recharge water continues to flow toward the well until the cone of depression is filled when pumping ceases.

Not all pumping in the Palo Verde region is replaced by Colorado River water. A small amount of pumping in the mesa may be derived from other sources. Limited recharge from the Chuckwalla Valley and McCoy Wash may provide a minor amount of groundwater recharge to the mesa. Finally, groundwater recharge from precipitation is negligible due to evaporation. (FSA, pp. 4.9-10-11)

Groundwater vs. Colorado River Water

Federal Regulation of Colorado River Water

As an interstate watercourse, the Colorado is subject to primary federal jurisdiction. There is a federal body of law that covers seven states and international treaties with Mexico. Conflicting historic claims to water rights under prevailing state law dates back to the late 1800s. Resolution of some of those claims has led to an incremental development of a multi-faceted body of law, collectively known as the Law of the River. As a result, there is full allocation of the Colorado River's annual flows, between upper basin states and lower basin states, which includes California, Arizona and Nevada.

The U.S. Supreme Court addressed conflicting claims over Colorado River water in *Arizona v. California* (1964). As the designated "Water Master," the U.S. Bureau of Reclamation (USBR) regulates the use of Colorado River water. As relevant to this proceeding, the Court's decree reduced California's allocation to 4.4 million acre-feet from the 5.2 million acre-feet California was using. Additionally, the USBR was authorized to regulate surface waters, including underflow to the extent the USBR determines that such underflow is part of the surface flows of the river. (8/1/05 RT 84:186:14) "Underflow" is the flow of river water laterally into the riverbanks and into the soil nearby."

In the 40 years of administration of the Court's Decree that the USBR may regulate underflow as part of the surface water accounting, the USBR has chosen to regulate only 3 wells, one in California and two in Arizona. These wells are located a few hundred yards from the River. The BEP II project wells are about 9 miles from the River. (8/1/05 RT 87:1 – 88:7)

As part of its long-term investigation about whether or not it should regulate a wider body of groundwater, the USBR sought information from the U.S. Geological Service (USGS) by way of a model of groundwater, surface water, and their relationships in the lower Colorado River Basin, including the Palo Verde Valley. This is referred to as the "accounting surface model." (8/1/05 RT 87:9 – 87:23)

In the 20 years of developing the accounting surface model and debating the policy of regulating a wider body of groundwater, the potential policy has become contentious with groundwater users in the lower basin, since it might jeopardize, or at least affect, use of groundwater. Recently, the USBR has indicated that it *may* implement regulation of groundwater originating from the River. The development of a groundwater accounting policy has been deterred by the physical, legal, and political complexities, and may be deferred indefinitely since water disputes between the California agencies with entitlements to the Colorado River appear to have been settled in the Quantification Settlement Agreement

(QSA). The QSA is to manage California's reduced allocation to 4.4 million acre-feet by use of water transfers, water conservation, and other means. To date, the USBR has imposed no regulation on groundwater use that the Energy Commission would consider an applicable law or regulation (8/1/05 RT 88:8 – 89:18; 106:7 – 107:6; Harvey/Smith, p. 4-6), and does not regulate groundwater use from any wells in the Palo Verde region where the BEP II project is located.

The Palo Verde Irrigation District
The Palo Verde Irrigation District (PVID) is the sole entity in the Palo Verde area with rights to divert and use Colorado River water. The PVID service area contains 131,228 acres along the Colorado River in southeastern Riverside and northeastern Imperial counties. The PVID diverts water from Colorado River for irrigation through a series of diversion canals originating at the Palo Verde Diversion Dam and returns water to the Colorado River through PVID drains. The PVID's diversion system includes approximately 244 miles of irrigation canals, carrying high-quality water Colorado River water to agricultural users. PVID has approximately 141 miles of open drains, carrying surface runoff, groundwater drainage, and canal operational spill return water back to the Colorado River.

PVID annually provides diverted Colorado River water to irrigate approximately 90,000 acres of farmland, primarily in the Valley. PVID has Priority 1 rights to irrigate up to 104,500 acres in the Palo Verde Valley, Priority 3 rights to irrigate 16,000 acres on the Palo Verde Mesa and Priority 6 rights to irrigate an additional 12,000 acres on the mesa. PVID has delivered surface water to approximately 1,250 acres of farmland on the mesa annually since 1980.

Irrigated crops consume a major portion of the water that PVID diverts. However, to irrigate crops effectively, the amount of applied irrigation water must exceed the crop-water requirements. The portion of the applied water that is not consumed by crops percolates downward past the root zone to recharge the underlying aquifer. However, when water table levels rise to the elevation of the drains, groundwater discharges to the drains and is returned to the Colorado River. (FSA, pp. 4.9-19-20)

According to Staff, during the 10-year period including 1987 to 1999 (excluding 1992 through 1994), the PVID's average annual diversion was approximately 913,000 acre-feet and the average annual return was approximately 513,000 acre-feet, resulting in a net average annual use of approximately 400,000 acre-feet. Given the total flows diverted and returned, the PVID's annual diversions and return flows from the Colorado River represent approximately 11.5 percent and 5.1 percent, respectively, of the river's annual flow volume. (FSA, p. 4.9-20)

The Applicant testified that PVID diverts up to about 1 million acre-feet or Colorado River water and returns 500,000 acre-feet to the River. (8/1/05 RT 91:15 – 92:2) The Applicant further testified that the amount of water actually diverted and returned is measured with margins of error. The USBR estimated the lower Colorado River flow is about 6 million acre-feet, with a margin of error of 15 percent or 900,000 acre-feet.

PVID uses a dimensional weir to measure the one million acre-feet water diverted from the River, with a 5 percent margin of error. That would be plus or minus 50,000 acre-feet at the inlet. PVID returns about half of its diversion, 500,000 acre-feet to the River, with a margin of error of 10 percent. Thus, the return flow also has a plus or minus error of 50,000 acre-feet. (8/1/05 RT 115:5 – 116: 9)

Groundwater primarily supplies municipal water users in the valley and most water users on the mesa. In the valley, the largest groundwater producer, the City of Blythe, delivers groundwater to a population of about 12,200, who live within a 6-mile radius. Agriculture is currently the largest user of groundwater on the mesa. Based on PVID's earliest records, farmland irrigated with *groundwater* on the mesa has declined from over 3000 acres in the early 1970's to less than 1,000 acres presently.

The existing BEP I is the second largest user of groundwater on the mesa, with an estimated average annual production of 3,300 acre-feet during normal operations. Also located on the mesa, the Blythe Airport and the Mesa Verde community, as well as small commercial and private homes use groundwater.

Groundwater pumping within the PVID service area is accounted for as part of PVID's reported Colorado River consumption, based on the "Diversion Less Return" accounting system. Within the PVID service area, irrigation water, water from canals, drains and excess irrigation percolates to the groundwater table. High groundwater levels in the Valley are maintained by this percolation of irrigation water provided by PVID. Groundwater pumping within the PVID service area draws water from the aquifers recharged by the percolated irrigation water. (FSA, pp. 4.9-20-21) PVID supports the project's proposed use of groundwater. (FSA, p. 4.9-41)

In a letter to the Energy Commission dated September 16, 2003, the PVID stated that the project's use of groundwater is not an illegal diversion of the District's allocation of Colorado River water:

> It should not be assumed or concluded that the Blythe Energy Project's wells are unauthorized or that, even if they are diverting water from the river, there is no right to do so. The water delivery agreements give no support to such arguments and where wells are within districts authorized to use water, it is assumed that the well within the district are not additional diversions for the river, and that such wells are not unauthorized diversions. (Harvey/Smith, p. 7)

Energy Commission Staff

Staff contends that the project's groundwater pumping on the Palo Verde mesa produces a chain of responses in the hydrologic cycle, causing the project to make unauthorized use of Colorado River water. Staff believes that under the 1964 Supreme Court Decree groundwater is the same as surface water. (8/1/05 RT 196:18 - 24) Beginning at the project site, BEP II groundwater pumping would produce a cone of depression, producing water that is stored in the aquifer. However, the cone of depression would continue to expand, extending from the well until it intercepts a source of recharge.

The PVID Rannells Drain, located about 1 mile east of the project, is the nearest source of potential recharge to the project. Staff has calculated that BEP II drawdown would cause the pressure gradient from the cone of depression to intercept the Rannells Drain in less than a week, which would begin to induce recharge from the Drain. Once the cone of depression intercepts the Drain, the pressure gradient figuratively “stops looking” within the aquifer for another recharge source, and only the Drain recharges the drawdown. The increase in groundwater recharge from the Rannells Drain caused by BEP II pumping would correspondingly decrease the drain return flows to the Colorado River, in the same amount as the power plant use. When BEP II pumping stops, the cone of depression will eventually be refilled with Drain return water. The cone of depression would not be recharged by underflow, directly from the River. (FSA, pp. 4.9-42; 8/1/05 RT 152:25 – 180:21)

Staff believes that in light of reductions in California allotment of Colorado River water and growing urban demand by the Metropolitan Water District (MWD) and San Diego County Water Agency, *any* decrease to return flows to the River is a change in the environmental setting, which represents a significant impact upon downstream users under the California Environmental Quality Act. This is so, even though the Applicant has proposed a Water Conservation Offset Program, since the Applicant’s Program is not sufficient in Staff’s view to verify a real reduction in agricultural consumption. (8/1/05 RT 177:1 – 180:21)

Applicant

The Applicant testifies that the project groundwater is not hydrologically connected to the Colorado River in “real time” as asserted by Staff. The Rannells Drain return water, which Staff says recharges the aquifer, would travel at the molecular level only 600 feet toward the BEP II well head over a 30 to 40-year pumping period. Staff agrees with this rate of movement of recharge water. (8/1/05 RT 117:15-24; 158:19 – 159:10) Applicant states that no legal decision in California has ever considered groundwater from a deep well located miles from a river channel to be directly linked to or classified as surface water. Thus, the BEP II groundwater use, which is not regulated by any state, Federal or local agency presently, is not an unauthorized use. (Harvey/Smith, p. 4, 6)

The Applicant contends that groundwater pumping does not cause a significant environmental impact. The Palo Verde mesa aquifer stores almost 7 million acre-feet of groundwater, and, though not “topped-off,” is full due to substantial cessation of irrigation on the mesa. The adjoining Palo Verde Valley aquifer stores another 5 million acre-feet and is “topped-off” due to constant agricultural recharge. From this combined 12 million acre-feet of constantly recharging regional groundwater storage, the BEP II project will pump 3, 300 acre-feet. The aquifer is 500-feet of saturated soil below the project. At most the BEP II project would cause a temporary drawdown of the water table by 5 to 10-feet. (8/1/05 RT 135:4 – 136:23)

Moreover, given the margins of error in estimating total annual River flows and Rannells Drain return water, the 3,300 acre-feet of recharge attributable to project pumping is insignificant. With a 50,000 acre-feet margin of error on the intake from the River and 50,000 acre-feet for the return water to the River, the 3,300 acre-feet attributable to the project is undetectable to the downstream users. (8/1/05 RT 116:10 - 21)

There are hundreds of wells in the Palo Verde Valley and mesa, none of which are regulated by the USBR or PVID. However, in recognition of the potential for the USBR to someday regulate groundwater extraction, the Applicant proposes a voluntary Water Conservation Offset Program (WCOP). The WCOP was created in consultation with the USBR, PVID and the City of Blythe. The WCOP is to rotationally fallow or retire irrigated lands to offset the consumption of groundwater. The PVID does not require a WCOP for the BEP II project. PVID does require a WCOP from MWD, for example, to allow inter-basin transfers of water from the River to the South Coastal Basin. The USBR acknowledged that the Applicant's WCOP meets the USBR's needs if there is a future policy to account for groundwater use. For now, the WCOP is not needed to comply with any applicable law or as mitigation for any impact. (8/1/05 RT 92:14 – 99:16)

Commission Discussion

The Commission finds that Palo Verde mesa groundwater and Colorado River water are legally distinct. The overland owner has rights under California law to use groundwater. Other than the few cases of underflow, the USBR has not asserted jurisdiction to directly regulate groundwater use from wells that are known to be in aquifers that are recharged by Colorado River water.

Currently, however, the USBR *indirectly* regulates such groundwater through the allocation and accounting system for providers such as PVID. PVID's allocation of Colorado River water receives a "credit" for all return water returned to the River. However, that "credit" is reduced by irrigation water and canal water that percolates into and recharges the underlying aquifer. BEP II's use of groundwater from on-site wells is not an unauthorized use under state or Federal law.

Additionally, the Commission finds that BEP II groundwater pumping does not cause a significant project or cumulative impact under the California Environmental Quality Act, in the context of the use of groundwater. (Below, we discuss the potential for groundwater degradation due to upwelling of salinity.) The mere change of the hydrologic setting, from Rannells Drain return water flowing to the River versus a portion of that return water recharging the groundwater, is not inherently a significant impact. In the context of PVID's volume of return water back to the Colorado River, the amount of recharge water (0.6%) is not significant. With the measurement methods employed on the River, the recharge water volume is not only insignificant, it is undetectable by measurement, even though it is actually happening according to physical laws of hydrologic recharge.

The Commission is extremely mindful of the potential impact of power plants on California's water resources. Our 2003 IEPR emphasizes the need for conservation and intelligent use of available water resources. Just as we laud combined cycle generating technology for its ability to recover and efficiently use waste heat, the Commission sees that in this case the groundwater has been recovered from water previously used for irrigation. With virtual certainty, the water that will recharge the aquifer in response to project pumping will be water dedicated initially to agricultural use. We are aware that some of the recharge water will be operational spillage; but this PVID water is effectively being used twice. Initially, it is dedicated to agricultural use, a significant segment of California's economy. Then it is recovered and stored in an aquifer as degraded groundwater to be used again for electricity production, also a significant and necessary segment of California's economy and welfare.

Therefore, the proposed use of groundwater for project cooling does not violate any applicable federal law or policy and conforms to applicable California laws and water policy.

Brackishness

The groundwater beneath the Palo Verde Mesa near the BEP II site has a TDS (i.e., 920 - 1100 ppm TDS) marginally greater than the 1,000 ppm TDS categorized as “brackish” by State Water policy. (8/1/05 RT 81:2 – 5) From this, the Applicant has argued that the BEP II groundwater is “brackish” and eligible to be used to cool its power plant in accordance with Resolution 75-58. (Harvey/Smith, p. 11)

To the contrary, Staff contends the project groundwater is actually drinking-quality water and, thus, highly disfavored as cooling water under Resolution 75-58. While the project groundwater slightly exceeds the minimum TDS level, chloride content is a second component of the definition of “brackish” under Resolution 75-58. The groundwater chloride level of 200 is below the 250 criteria for chloride. (8/1/05 RT 171:7 – 172:8)

Staff testified a 1,000 ppm TDS level is equivalent to the state’s secondary Maximum Contaminant Level (MCL) for drinking water, exceedance of which does not render such water unfit for use as drinking water or any other beneficial use. Secondary MCLs are aesthetics-based, water quality standards that are applicable to public water systems, and are set to protect odor, taste, and appearance. They do not prevent this water from being used as a source of drinking water or to satisfy other beneficial uses, which it does for those users dependent on it and who have no other source of water.

Staff testified that this groundwater meets the definition of “Fresh Inland Waters” with regard to domestic, municipal, and agricultural water supply beneficial uses. This groundwater aquifer is a “source of drinking water” under the more recent State Board Policy 88-63, the “Sources of Drinking Water” policy for the state, and is currently used in nearby Mesa Verde for just that purpose. This groundwater is of substantially higher quality and greatly exceeds any of the requirements of Policy 88-63 that would qualify it to be exempted as a source of drinking water. (FSA, p. 4.9-71) Thus, if the project groundwater is being used in the same way “fresh” water is used, then the project groundwater is “fresh” water. (8/1/05 RT 241:16 – 19)

The Applicant testified that Riverside County has cited the Mesa Verde groundwater supply as not meeting federal EPA drinking water standards and is requiring an alternative clean drinking water source. To provide better water, the City of Blythe is extending its high-quality water pipeline to the Mesa Verde community. (Harvey/Smith, p. 11)

Commission Discussion

The testimony from both Staff and Applicant is correct in that the groundwater beneath the BEP II site has a TDS marginally greater than the 1000 ppm TDS categorized as “brackish” by State Water policy. Chloride level is marginally under “brackish” by State Water policy. The Commission is in the same position in BEP II as in BEP I.

It is important to note that BEP II is not using "fresh" water for cooling purposes as defined by law and policy. The quality of the groundwater to be used is poor. Staff also found the quality to be poor, although it declined to use the word "brackish." Instead, Staff argues that, by analogy based upon similarity of use, marginally brackish water should be treated as "fresh" water.

Consequently, before the Commission can determine whether use of the BEP II groundwater would conform to State Water policy, we must determine whether there are reasonable alternative water supplies or cooling technologies.

<u>Other Waters/Cooling Options</u>
Energy Commission staff reviewed possible alternative water supplies and cooling technologies that are pertinent to this discussion:

- Reclaimed Water from City of Blythe's Wastewater Treatment Plant (WWTP);
- Rannells Drain Return Water from PVID;
- Dry Cooling or Hybrid Cooling (1/3 Wet and 2/3 Dry)

Reclaimed Water From City Of Blythe's WWTP
The City of Blythe's Wastewater Treatment Plant (WWTP) was placed into operation in 1979 at an initial capacity of 1.5 million gallons per day (mgd). The existing capacity of the City's WWTP is 2.4 mgd. During 1991 and 1992, the City initiated a Wastewater Treatment Facility Analysis to consider alterations needed to improve the reliability of meeting its discharge criteria as well as to increase its capacity to meet projected populations to the year 2010. The projected 2010 WWTP flows were expected to result in average daily flows of 1.7 mgd in winter and 2.5 mgd in summer.

The City of Blythe treats its wastewater to advanced secondary treatment and discharges its effluent into percolation ponds located onsite at the WWTP, which serve to recharge the groundwater aquifer. Total dissolved solids (TDS) concentration of the wastewater effluent is about 1,185 mg/l. PVID believes the City of Blythe's wastewater effluent percolating to groundwater contributes to the flows returning to the Colorado River, which effectively reduces PVID's use of Colorado River water as accounted for by USBR.

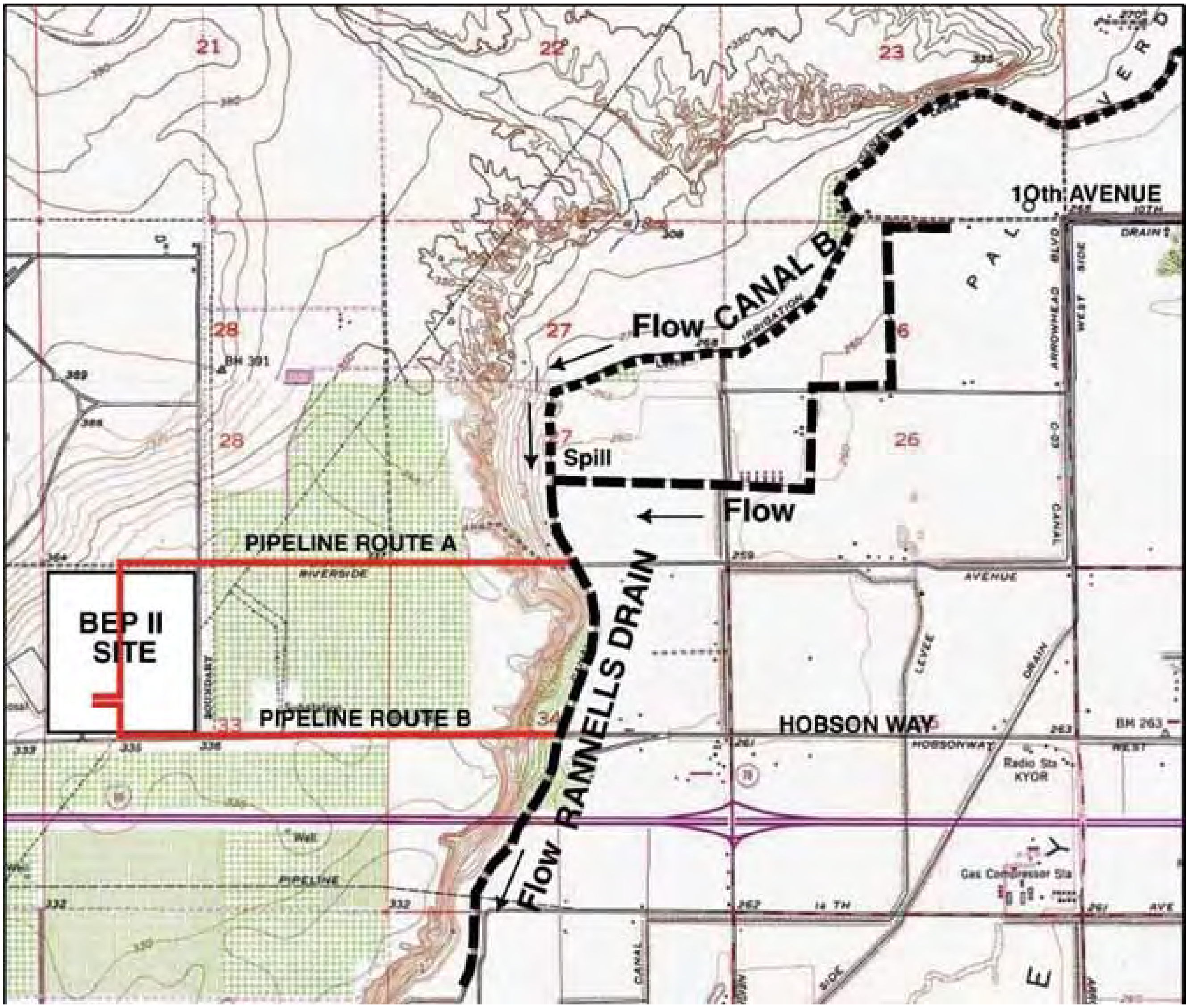
To meet current Title 22 regulations for use of reclaimed water for industrial cooling at BEP II, the effluent from City of Blythe's Wastewater Treatment Plant would need to be upgraded from advanced secondary to tertiary treatment. At this time, City of Blythe has neither any plans for upgrading its wastewater treatment plant to tertiary treatment nor plans for employing a reclaimed water program. Even though the Applicant could possibly fund this expense, or at least fund its proportionate share of the cost to implement tertiary treatment, this is not likely to occur.

Staff's view is that Reclaimed Water from City of Blythe's WWTP is not presently a viable alternative due to the following:

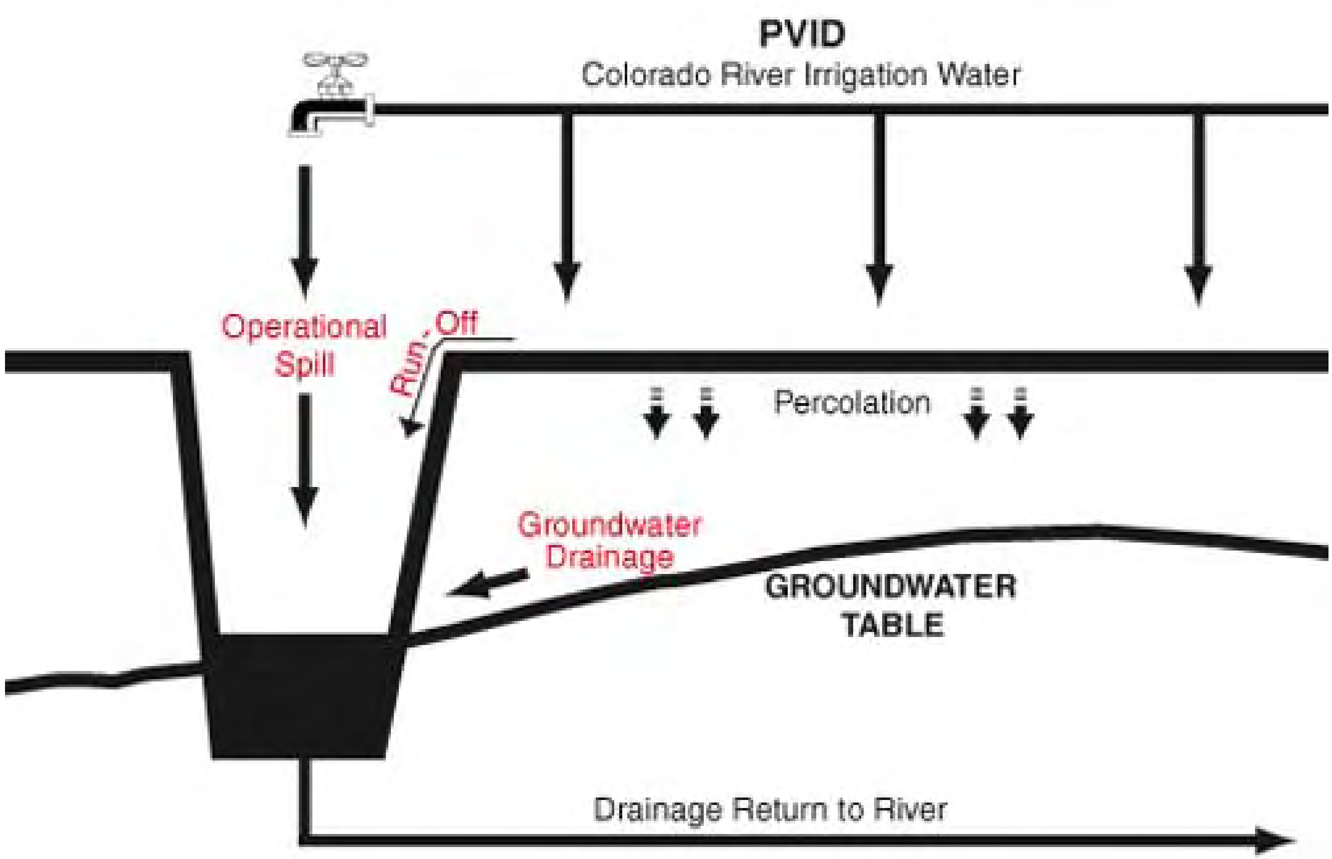
- The potential supply of reclaimed water is not sufficient to meet BEP II demands over the life of the project.
- City of Blythe does not have any existing or foreseeable plans to implement Title 22 tertiary wastewater treatment or a reclaimed water program.
- The use of reclaimed water would essentially use Colorado River water, because BEP II's use would preclude recharge to the groundwater aquifer and reduce PVID's return flows as accounted for by USBR. (FSA, pp. 4.9A-6-7)

Commission Discussion
The Commission finds that there is insufficient supply of adequately treated wastewater from the City of Blythe to be a reasonable alternative to the project's use of groundwater.

Rannells Drain - Irrigation Return Water from PVID
PVID operates a system of irrigation supply "canals" and return water "drains." The canals contain "fresh" water diversions from the Colorado River. The canals distribute that Colorado River water to farmers in the PVID service area.



As shown below, the drains carry three types of water back to the Colorado River, so that PVID is credited with its unused allocation. The return water is composed of runoff water, which may come from inefficient irrigation practices and deliberate over-watering to keep crop-harming salts from building up in the soil. In addition, irrigation water placed on crops percolates down through the soil. However, since the groundwater aquifer is essentially filled to the brim, the water table is just below field level. The drainage ditches are about 10 to 20 feet deep in order to intercept groundwater averaging (valley wide) about 10 feet below the ground surface. Consequently, not all irrigation water can continue to percolate down into the aquifer, so some of it moves sideways into the drain. This intercepted shallow groundwater is called “groundwater drainage.” Lastly, since farmers do not use not all “fresh” Colorado River water in nearby canals, there is an excess of such water that is returned to the Colorado River in the “drains.” This water is called “operational spill.” Operational spill combines with, and dilutes the far more saline blend of runoff and groundwater drainage. PVID’s Rannells Drain is about 11/2 miles from the project, and Canal B flows into the Rannells Drain.



Quantity
Staff testified that in the Rannells Drain, the normal range for return flow varies from a minimum average daily flow of 2 cfs during January to about 15 cfs during the balance of year. Minimum flows occur during a 2-week annual maintenance outage of the "fresh" water canals. Otherwise, Colorado River "fresh" water in Canal B and return water in the Rannells Drain occurs at higher flows for the balance of the year. The rate and pattern of flow in PVID's irrigation return drains is not expected to significantly change as a result of the recently approved Quantification Settlement Agreement. (FSA, p. 4.9A-8)

Without operational spillage, the flow in the Rannells Drain is 2-3 cfs, composed of runoff and groundwater drainage. Groundwater drainage in the Rannells Drain is a function of the extent of adjacent lands being irrigated for agriculture. Thus, "fresh" operational spillage contributes approximately 12 – 13 cfs to achieve the average flow of 15 cfs for approximately 11 months. (FSA, p. 4.9A-8)

The average and peak water demands for BEP II are 3.5 cfs (2.4 mgd) and 6.2 cfs (4.0 mgd). PVID indicated to Staff that during its normal 2-week outage in January that it could make special arrangements to provide continuity for meeting BEP II's water demands. During the outage, PVID could either impound drain water or provide canal water to BEP II's water delivery location on Rannells Drain. (FSA, pp. 4.9A-8-9: 8/1/05 RT 257:20 – 258:4) Staff also suggests that, during an outage, "fresh" water operational spillage would not have to be used as makeup water if the Applicant constructed a shallow well field to capture about 3.5 cfs (100 acre/feet) of degraded groundwater. (8/1/05 RT 260:11 – 261:5)

However, the Applicant testified that operational spill, which is required for sufficient water for project operation, is truly “fresh” water under Resolution 75-58, and so disfavored for power plant cooling. Plus, the use of Rannells Drain water is also disfavored since it uses return water that would otherwise go back into the Colorado River for use by downstream users. Lastly, the use of Rannells Drain return water would be specifically deducted from the PVID allocation, unlike the recharge of groundwater. Applicant testified that under strict interpretation of priorities under the Quantification Settlement Agreement, PVID’s loss of the returned drain water could come from the MWD’s entitlement. (8/1/05 RT 132: 23 - 134:25; Harvey/Smith, pp. 11 & 13)

<u>Brackishness</u>

The quality of water in the Rannells Drain is largely influenced by local agricultural activity, which degrades the drain water quality. But, diluting with Canal B operational spillage enhances the quality of the drain water ultimately returned to the Colorado River.

Staff testified that PVID typically collects water quality data on a quarterly basis for its canal supply as diverted from Colorado River and on a bi-annual basis for its irrigation return flows in Rannells Drain. Staff cites PVID’s observed TDS was 1,510 mg/l on an undisclosed date in September 2002 and 1,590 mg/l on March 14, 2003, as an indication of water quality in the Rannells Drain. On the same days, the “fresh” canal water diverted from the Colorado River was observed to have TDS concentrations of 552 mg/l and 728 mg/l, respectively. (FSA, pp. 4.9A-8) Staff also had Rannells Drain sampling data from 1967 to 1971, with an average 1,830 TDS and 1975 at 1,920 TDS. Staff testified that neither PVID nor the Applicant had been able to provide data showing TDS levels in the drain were lower than the BEP I groundwater TDS data. The Rannells Drain is about 1,600 TDS, whereas the project groundwater is 1,000 TDS. (8/1/05 RT 173:15 – 174: 8; 261:17 – 262:7)

Lastly, Staff testified that use of Rannells Drain water would be beneficial to the overall salinity of the Colorado River. Staff suggests that if the project could receive the Rannells Drain water *before* it was diluted with “fresh” operational spillage *and* substitute a shallow well field to pump degraded groundwater the quality of return water to the Colorado River would improve. (8/1/05 RT 256:5 – 257:1) If tied to a verifiable water conservation offset plan, use of Rannels Drain return water would conform to both State Water policy and the Commission’s IEPR. (8/1/05 RT 139:2 – 4)

However, the Applicant asserts Staff used too few data points to establish the high TDS level of the Rannells Drain water. While acknowledging the few data which do exist, the Applicant testified that information about the quality of the diverted water and the return water, when combined with a knowledge of how that canal and drain system are used throughout the year, leads to the conclusion that on a consistent, year-round basis the groundwater is more degraded than the Rannells Drain water. (8/1/05 RT 138:21 – 139:22)

The Applicant testified that during the low flow periods when there is insufficient return water for the power plant, TDS is actually 800 to 1,600 mg/l. For return water flows to be sufficient for the full range of power plant operations, Rannells Drain water must be supplemented with operational spillage. At such average or high drain water flows, the TDS content is diluted to about the same level as the source water from the Colorado River, about 500 - 600 TDS.

Thus, the Applicant contends that its project groundwater is actually of lower quality than the average Rannells Drain return water. (Harvey/Smith, pp. 11 & 13)

Commission Discussion

With regard to whether the Rannells Drain return water or the project well water is more brackish, the Commission finds that the testimony is inconclusive. While the Staff has some current data, the dilution ratio with the high quality operational spillage, which is required for most of the year, makes that data insufficient for a finding in which we would have confidence.

The Commission's determination of whether the Rannells Drain water is a reasonable alternative to the project groundwater turns on the predominance of "fresh" Colorado River water in the blend that is called "return" water when supplies are sufficient for full plant operation.

Hypothetically, had the Applicant initially proposed the project with the use of "blended" Rannells Drain water as the source of cooling water, the Commission would have expected that such a proposal would have provoked intense concern, and likely doubt, over whether the use of blended return water that contained so much "fresh" Colorado River water conformed to Resolution 75-58 and our 203 IEPR.

During 11 months of average to high flows, high quality "Canal B" water is present at a ratio between 5 – 6:1, compared to degraded runoff and groundwater drainage. When Canal B water would be unavailable due to maintenance, the project either doesn't operate or PVID supplies other "fresh" diversion water.

Or, the Applicant could implement Staff's last-minute suggestion of a shallow well field to pump degraded groundwater, which brings us full circle to face a junior version of the Applicant's groundwater proposal and an apparent contradiction in Staff's new suggestion to pump some groundwater versus its prior contention that *any* pumping of groundwater, regardless of the small percentage used, is a "significant" impact. (8/1/05 RT 164:19 – 165:24) However, the Commission can take percentages into account when determining significance.

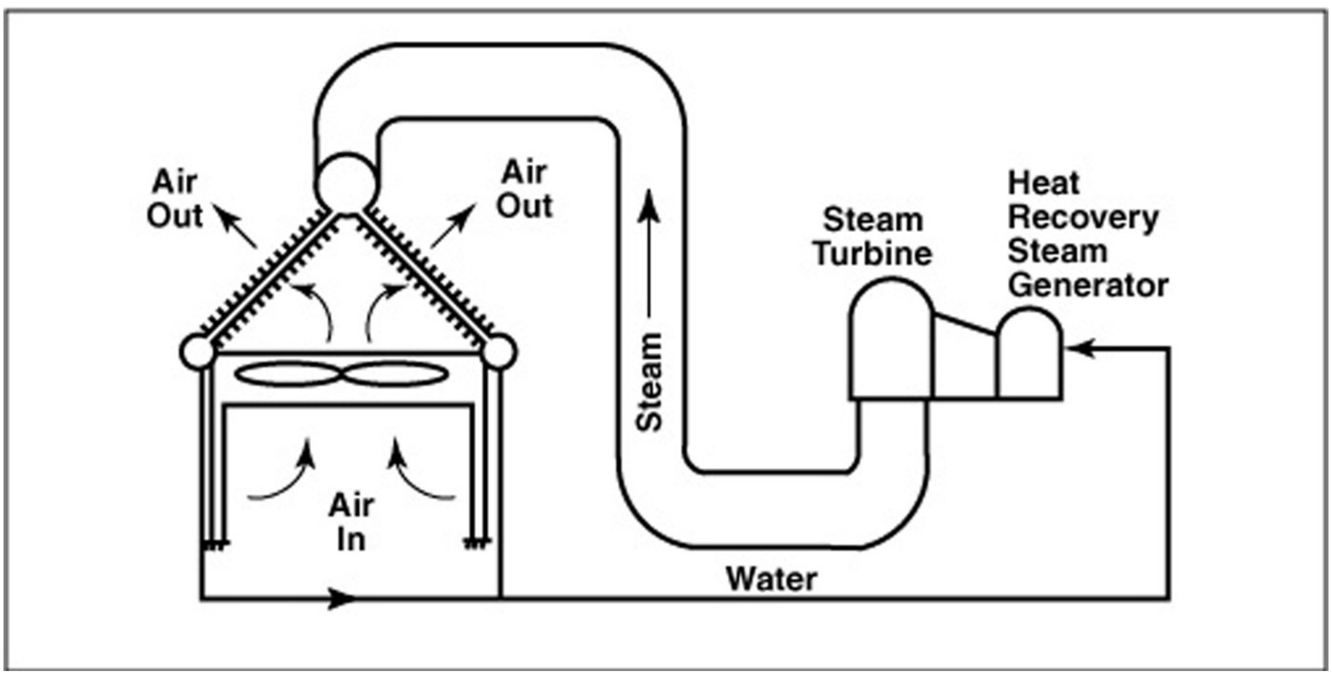
The Commission finds that "but for" the use of fresh inland water, namely PVID's canal water from the Colorado River, the Rannells Drain water supply would be insufficient for power plant operation. Currently, the Rannells Drain returns a significant portion of high quality, low TDS , "fresh" Canal B water to the Colorado River. Thus, the use of Rannells Drain water for power plant cooling does not conform to Resolution 75-58 and our 2003 IEPR. Rannells Drain water, therefore, is not a reasonable alternative to the use of groundwater.

Moreover, given the known trend to fallow or retire irrigable farmlands in the Palo Verde Valley through water conservation offset programs, the Commission cannot ignore the prospect that the degraded fraction of the drain water will become a progressively smaller component of the return water as irrigation is reduced. If this likely scenario was to occur and the power plant were relying upon the Rannells Drain for cooling water, the proportional use of “fresh” water would go up. Also, reduced irrigation could substantially affect the Staff’s shallow well field concept, requiring shallow wells to be drilled deeper. The reliability of the water supplied from Applicant’s deep wells would not be affected by the vagaries of irrigation levels.

As Staff says, a verifiable water conservation offset plan would “zero” the net effect of using the “fresh” water component of Rannells Drain water by ceasing irrigation with an equivalent amount “fresh” canal water. However, Applicant’s proposal to use degraded groundwater, leave the “fresh” component of Rannells Drain water to return to the Colorado River, and save “fresh” canal water through a verifiable water conservation offset plan provides greater overall benefits.

Dry Cooling

Dry cooling, or non-evaporative cooling, is accomplished using air-cooled condensers. The dry cooling towers consist of multiple finned heat exchange tubes mounted on a large steel framework as shown in the schematic representation below:



Dry cooling is somewhat like an automotive radiator, but much larger. The cooling medium is ambient air. So, the hotter the ambient air, the greater the cooling challenge. Fans are used to draw air in the bottom of the frames and direct it upward through the bundles of tubes discharging the warmed air to the atmosphere. The tubes are internally fed with exhaust steam from the steam turbine. The steam turbine exhaust is transported in steam ducts 13 to

17 feet in diameter. These very large ducts distribute steam to increasingly smaller headers and eventually to tubes of approximately 1-inch diameter. Dry cooling requires more than twice the power to operate the fans, compared to wet cooling. (FSA, p. 4.9A-19)

The cost of dry cooling is generally greater than the cost of wet cooling both in terms of capital cost and operating cost. Additionally, dry cooling causes a reduction in the ultimate capacity of the steam turbine at higher ambient temperatures. The amount of reduced capacity of the steam turbine is a function of balancing the greater capital cost of the dry cooling in relation to the lost revenue of the lower peak capability on the few high ambient temperature days. According to Staff, the final selection of dry cooling size varies with an applicant's view of future power prices during peak conditions and overall project-specific economic objectives. This is an important issue since only an applicant can perform the final optimization of plant design in compliance with its specific project economic factors and belief in future power sales. (FSA, p. 4.9A-21)

However, in Staff's view the BEP II project is still competitive with a 3.5 or 4.5 percent increase in production costs. (8/1/05 RT 399:20 – 401:1) Staff also believes that the Applicant has overestimated any financial penalties that may arise from not being able to provide scheduled output under a prospective contract with SCE. (8/1/05 RT 416:5 – 21)

Other than economics, the most important variables in determining the cost and performance of cooling alternatives will be potential noise and visual impacts. Additionally, the proximity of the Blythe Airport means that the thermal plumes from the dry cooling towers need to be analyzed in consideration of aircraft safety. (FSA, p. 4.9A-21)

Staff conducted an Exhaust Plume Turbulence analysis concluding the following:

1. Dry cooling thermal plumes would have the potential to cause significant turbulence over a much wider range of ambient conditions and number of hours annually than the wet cooling tower thermal plumes.
2. Dry cooling thermal plumes would be more resistant to the effects of wind than wet cooling tower thermal plumes;
3. Dry cooling thermal plumes would cause air turbulence at low altitudes.
4. Turbulence caused by the dry cooling thermal plumes would likely be worse than that caused by the wet cooling tower during warmer ambient temperatures and during periods with higher wind speeds.

Therefore, Staff determined that the use of dry cooling for the proposed BEP II would cause significant impacts on aircraft safety at the proposed site. Consequently, Staff suggested retaining dry cooling but relocating the project away from the airport.

The use of dry cooling would increase cooling system and overall power plant noise levels. Compared to wet cooling, the use of dry cooling would require substantial additional noise reduction, at an increased cost of about $1 million. (FSA, p. 4.9A – 42; 8/1/05 RT 393:24 – 394:3)

The dry cooling towers would be visible as a large, elevated, geometric structure that would appear prominent and quite massive from foreground to middleground viewing distances along Hobsonway and I-10. The structure would increase the proposed project's industrial visual character, and would result in greater visual contrast and view blockage when compared to the proposed project. By comparison, the 45 cell dry cooling tower would be approximately 115 feet (tall) x 350 feet (long) x 200 feet (wide); the wet cooling tower would be 40 feet (tall) x 472 feet (long) x 52 feet (wide) wet cooling tower. Staff believes that while the resulting visual impact would be adverse, various factors including quality of the existing view, type of viewers, duration of view, and angle of view would cause the impact not to be significant from Hobsonway and I-10. (FSA, p. 4.9A - 46)

Applicant

The Applicant acknowledges that dry cooling is technically feasible in the desert environment, but for the BEP II project economically infeasible to operate in the configuration Staff suggests with the likely scheduling demands of the electricity marketplace. The Applicant had bid the recently withdrawn Southern California Edison (SCE) solicitation for 1,500 megawatts, which likely would require the project to operate as an intermediate facility with numerous start-ups, perhaps daily, during hot times of the year.

Applicant testified that the Staff has underestimated the capital costs of dry cooling equipment by $20 million. Dry cooling would cost $55 – 60 million more than the proposed wet cooling. Some of that added cost arises from the fact that the Applicant designed BEP II to be a turnkey version of BEP I and so has already purchased the components affected by a change to dry cooling. Those components would have to be returned to the manufacturer for significant changes to adapt to dry cooling at additional cost. (8/1/05 RT 361:1 – 362:13)

Trying to operate the project with dry cooling in the hot desert also imposes operational penalties, which in turn affect the economic viability of the project. On a 110-degree day, the power plant produces 27 fewer megawatts with dry cooling than with wet cooling. That is a 2.5 percent loss of operating efficiency and a 5.5 percent loss of output. The average high temperature in June is 105 degrees; July is 108 degrees; and August is 107 degrees. Peak temperature during such months, when electricity demand will be the highest in Southern California, is 120 –125 degrees. (8/1/05 RT 366:1 – 368:3)

On such hot 110-degree days, the Staff-suggested dry cooling tower, which was minimally sized for minimal cost, would be below steam turbine back pressure limits, not allowing the facility to be brought online. The worst case arises if the plant is tripped off-line during a hot day and attempts to restart. The combustion turbines must be run at a sufficient load to match the steam turbine rotor temperature for the restart. This cannot be achieved with the Staff-sized dry cooling tower or any other reasonably sized dry cooling tower. Rather, the facility would have to be shutdown overnight or longer to lower the steam turbine rotor temperature. (8/1/05 RT 368:21 – 370:23) The Applicant believes that under the likely terms of a power purchase contract, it would not only lose revenue when shut down but would be liable for the exceptionally high costs of replacement power. (8/1/05 RT 379:17 – 381:24)

Air quality emissions during cold start-up will be out of compliance for nearly twice as long as with wet cooling, while waiting for the HRSG and steam turbine to come up to operating temperature. Since the facility will likely operate in an intermediate mode, with 200 or so starts per year, the added, non-compliant emissions from the dry cooling configuration are problematic. (8/1/05 RT 372:7 – 372:13; 390:11 - 22)

Applicant believes that dry cooling towers would have to be enlarged to 70 cells, not 45, just to operate most of the time. Seventy-cell dry cooling towers would create undesirable noise and visual impact. The Applicant believes that noise abatement to reach levels comparable to wet cooling would cost an added $2-6 million. The footprint for the dry cooling tower would be about 31/2 times larger than the wet cooling towers. (8/1/05 RT 361:1 – 362:13; 377:17 – 378:5; Cameron/Gavahan/Deen, p. 7)

Commission Discussion

The Commission finds that dry cooling in the desert environment is technologically feasible. In addition to the higher capital costs of dry cooling there are significant operational penalties arising from the hot desert environment, which translate into reduced output and increased production costs. Staff evaluated dry cooling for a baseload plant operating continuously around the clock, rather than the stop-and-start load following profile likely in today's market. Moreover, the size of dry cooling towers Staff analyzed appear to be unable provide sufficient cooling during hot weather when the electric loads are the greatest. The BEP II project needs to be capable of operating, including multiple start-up and hot re-starts, when Southern California's power demand is high. The dry cooling towers that Staff analyzed are huge compared to the wet cooling towers proposed by the Applicant. Moreover, for optimal power plant operation, the Staff-analyzed dry cooling towers appear to be under-sized and thus under-priced. Additional disadvantages to the dry cooling towers include more noise, greater visual impacts, and more serious thermal plumes. Dry cooling is neither environmentally nor economically reasonable for this project.

Staff also considered hybrid cooling, which is a combination of 2/3 dry cooling (30 cells) and 1/3 wet cooling (1 cell), as a way to reduce the project's water consumption, down to about 1,000 acre-feet per year. Briefly, hybrid cooling could use Rannells Drain water. Compared to wet cooling, capital costs would be higher, output and operational flexibility would be reduced in hot weather; and for noise, visual impacts, thermal and visible plumes hybrid cooling would be between wet and dry cooling. Again, given that wet cooling does not create significant impacts, we conclude that hybrid cooling would likely be better than dry cooling, but not a reasonable alternative to wet cooling.

Commission Conclusions

The marginally brackish quality of the BEP II's proposed groundwater caused the Commission to consider other available water supplies in the vicinity of the project or other cooling technologies. Wastewater is not available in sufficient quantity for the project. Rannells Drain water would contain a blend of waters including substantial "fresh" water, would be included in PVID's accounting, and would reduce in "real time" the flows returned to the Colorado River and downstream users. This drain water source is less desirable for power plant cooling than marginally brackish groundwater, which is recharged over time and indirectly accounted for by PVID in net water use.

Dry cooling, while technologically feasible, is not practically feasible for this project and to meet this project's objectives. The "proxy" dry cooling towers studied by Staff would likely have to be substantially enlarged to allow the facility to operate most of the time in average hot conditions as a *baseload* facility. Moreover, to meet electricity market conditions, the project intends to operate as an *intermediate* facility, with many start-ups. Dry cooling is not well-suited for such a facility in the hot desert environment. Dry cooling towers cost more to install as well as to operate, due to operational inefficiencies. Dry cooling towers would create substantially worse noise, visual and thermal plume impacts than wet cooling. Dry cooling is not preferable. Hybrid cooling reduces some of the disadvantages of dry cooling, but not sufficiently to make it preferable to wet cooling.

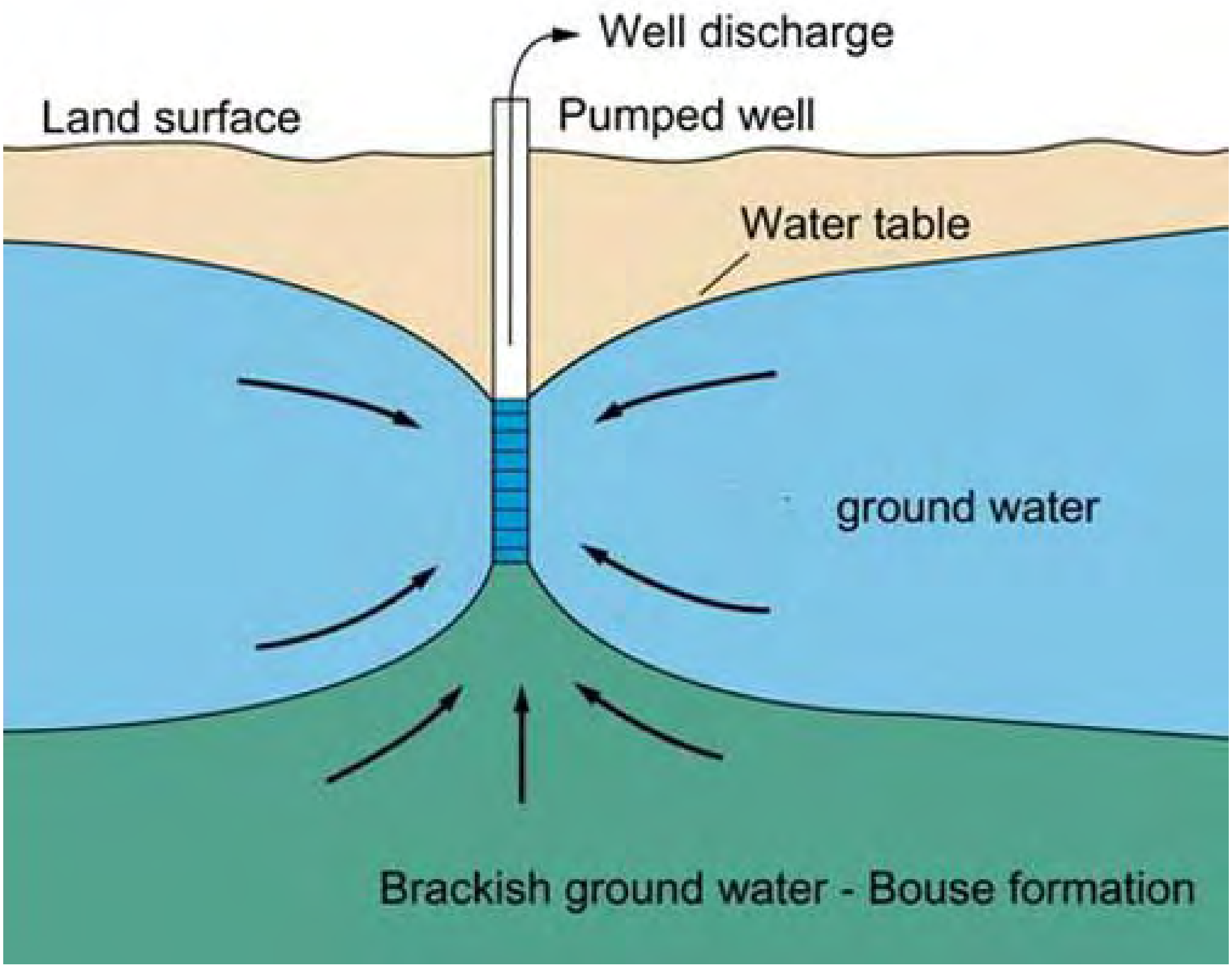
Therefore, the proposed use of groundwater for BEP II project cooling conforms to Resolution 75-58 and our 2003 IEPR policies.

<u>Salinity</u>

The USGS reports that TDS in groundwater wells in the mesa increases with depth and distance from the Palo Verde Valley. The primary reason salinity increases with depth is because the mesa aquifer, composed of Older Alluvium, is directly underlain by the Bouse Formation, which consists of marine sediments containing brackish water. Brackish water from the Bouse Formation has slowly diffused into the fresh water of the mesa aquifer over time. (FSA, p. 4.9-37)

The USGS estimates that the Bouse Formation occurs at an approximate depth 600 to 700 feet below land surface on the mesa in the vicinity of the BEP II. Although most mesa wells described by the USGS are completed to depths of less than 400 feet, the deeper wells surveyed by the USGS provide an indication of the potential salinity of the Bouse Formation. The three wells that were completed to a depth of 600 feet yielded water containing TDS concentrations ranging from 2,160 to 3,020.

The USGS cautions that increases in groundwater pumping in the mesa would likely cause transport of lower quality water up into the fresh-water aquifer. This process commonly occurs in deep wells constructed in alluvial systems underlain by marine or brackish formations. Although most water flows horizontally through an aquifer system to pumping wells, pumping also causes vertical flow. Upward vertical flow to a well is commonly called upwelling. The rate of upwelling would increase as deep wells approach or penetrate the Bouse formation. Higher pumping rates would also increase the rate of vertical flow. (FSA, p. 4.9-38)



Staff
Staff contends that the BEP II project wells will come within 150-feet of the top of the Bouse Formation and over time with high-volume pumping will cause an upwelling of saline waters. In turn, that upwelling will degrade better quality waters in the aquifer, which will cause a permanent adverse impact to potential future well operators. With the proximity of the BEP I wells, there is a potential for saline waters mixing between the BEP I and BEP II wells.

By the end of project operations, there will be a "cloud" of permanently degraded water up to the side inlet holes of the well. It would take 5 to 10 years of operation before the saline water reached the pumping wells. At that time, the more degraded water, with higher TDS than before, would enter the wells and be used by the project. The more saline water would not go back into the Bouse Formation with the passage of time.

Upwelling would decrease with distance from the project production well but could occur anywhere within the cone of depression, which extends miles beyond the project site boundaries. Existing wells located in the vicinity of the project site would likely be affected by increases in salinity caused by project pumping. Also, wells installed nearby in the future would encounter degraded water at less depth. Staff asserts that, under CEQA, the degraded aquifer water is a significant impact. (8/1/05 RT 207:7 - 215:4)

Applicant

Applicant testified that any upwelling would be in the immediate vicinity of the well due to the effect of the cone of depression. Any degraded water will be drawn into the well. Further, Applicant testified that any potential degradation is reversible once the pumping ceases and with the passage of time. No more water will be drawn upward. (8/1/05 RT 118:7 – 121:17)

Commission Discussion

The Commission believes that over time project pumping will cause a change in the existing aquifer setting, between the well intakes and the top of the Bouse Formation. The Commission expects upwelling to reach the bottom of the well in 5 to 10 years. The upwelling movement of saline water will essentially cease when operations cease.

There are no other existing wells in the vicinity of the project, other than BEP I, which go to a comparable depth. (Staff Exhibits – Palo Verde Mesa; Groundwater Quality Sampling & Map) So non-power plant wells would not be affected by any upwelling from the project. Both BEP I and BEP II anticipate consuming any water which becomes more saline due to upwelling and are designed to accommodate more saline water. Any future well drilled in the vicinity of the BEP II project can avoid any aquifer water degraded by upwelling by not drilling so deep. (8/1/05 RT 215:5 – 19)

The Commission finds that project groundwater pumping will not cause a significant impact to aquifer water by the upwelling of more saline water. In the future if a well is drilled in the vicinity of the project, the effect of any upwelling can be mitigated to insignificance by reducing the depth of the new well. Given the thickness of the aquifer, there is abundant, and generally better quality, groundwater for a well at less depth.

Water Conservation Offset Program

Notwithstanding that the USBR is not currently regulating groundwater withdrawals or requiring that such withdrawals be offset, the Applicant has voluntarily proposed a Water Compensation Offset Program (WCOP) anticipating that such regulation may someday occur. The Applicant proposes to fallow or retire irrigated lands in an amount equal to the groundwater withdrawn. (Harvey/Smith, p. 17, 18; 8/1/05 RT 94:11- 21)

The BEP II WCOP parallels the WCOP of BEP I, with important new restrictions on how recently lands were irrigated. In the BEP I Decision, the Commission stated:

> The need for a Water Conservation Offset Program is not driven by a finding of adverse environmental impact, or need to mitigate under existing LORS. Therefore, the WCOP, in this case, is sufficient to satisfy the Commission's concerns. (Decision, p. 208)

Both the USBR and PVID were consulted in the preparation of WCOP and have approved its adequacy to address water concerns related to a potential, but speculative and perhaps unlikely, Colorado River accounting system that would include all regional well water users as part of PVID's Colorado River surface water entitlement. (Harvey/Smith, p. 14; USBR Letter, 6/14/02)

The BEP II WCOP will target 786 acres to be acquired and confirmed prior to commercial operation and selected from eligible acreage in the Palo Verde Valley or mesa. The final submitted WCOP provides for an average consumptive water rate use of 4.2 acre-feet per acre. This figure was derived from consultations with the USBR and MWD. PVID has expressed that the consumption rate number is too low, with the PVID claiming averages from 4.6 to 5.0 acre-feet per acre. The Applicant believes that the conservatively low consumption rate obviates the need for crop and water use history on selected lands. (Harvey/Smith, p. 15) Applicant consulted with MWD in the preparation of the WCOP for BEP II. MWD objected to the eligibility of lands irrigated in the last 10 years in the BEP I WCOP. As a result of issues arising in the BEP I WCOP, the proposed WCOP specifies that the lands have to have been irrigated in the last five years. MWD also objected to the BEP II WCOP's initial suggested use of 4.6 acre-feet per acre since the MWD wanted to use a more conservative 4.2 acre-feet in its WCOP, thereby fallowing more acreage. The Applicant adopted 4.2 acre-feet per acre as its final WCOP consumptive rate. With those changes, MWD concurs with the BEP II WCOP. (8/1/05 RT 102:22 - 106: 4)

Applicant testified that retirement and/or fallowing of eligible lands under its WCOP does not cause erosion impacts. Under the fallowing option, 786 acres of irrigated farmlands would not be actively farmed during the life of the project. Consequently, dust (PM_{10}) emissions associated with tilling, planting, and harvesting those farmlands, as well as farm equipment and delivery truck emissions would be eliminated. Fallowed lands will be rotated on a two to three year basis. The Applicant has agreed to use clod tillage and stubble maintenance on fallowed lands to reduce erosion, even though it believes such measures are unnecessary. Two Environmental Impact Reports for the MWD/PVID and IID/San Diego water transfers found the erosion from fallowing was less than from active farming operations, but implemented similar erosion control mitigation. (Harvey/Smith, p. 16; 8/1/05 RT 100:1-101:24)

If a rotational fallowing program is used exclusively, no farmlands will be permanently retired or converted from agricultural use. However, if lands are permanently retired, the WCOP will have potential impacts associated with the loss of productive farmlands. To mitigate any impact to productive farmlands from permanent retirement, the Applicant will offset any retired farmlands through obtaining permanent farmland conservation easements, payments into farmland trust organizations, and/or participation in the Riverside County farmland conservation program. (Harvey/Smith, p. 17)

The Applicant notes that no other groundwater user has a WCOP, so the WCOP is unique to the USBR. (Harvey/Smith, p. 18) In contrast, the MWD's WCOP with the PVID is based upon its inter-basin transfer to allow 100,000 acre-feet of Colorado River surface water to be re-directed from agricultural use in the PVID to uses in the South Coast. (8/1/05 RT 94:21 – 97:3) The PVID would not require a WCOP in order for the project to pump groundwater, since groundwater recharge is already accounted for in PVID's net entitlement. (8/1/05 RT 97:12 – 98:15)

The Applicant proposes to report water use and acreage of land retired from irrigation to USBR and PVID annually. If the land retired or fallowed was previously served by surface water, BEP II's report will include records from PVID's database showing that no water was now delivered to the particular fields. For land previously irrigated using groundwater, or sharing a point of water delivery with a field continuing to be irrigated, photographic evidence would be provided. (FSA, p. 4.9-26)

Staff

Staff's concerns with the proposed WCOP stem from inadequacies in erosion control measures and the inability to accomplish water conservation as proposed. The Applicant included the following conservation measures in the WCOP:

- Maintenance of stubble residue for fields previously planted in alfalfa, wheat, barley, or similar crops; and
- Clod tilling for non-irrigated fields without stubble residue or sod cover. Mulch or similar material would be integrated into the clods on soils classified as Highly Erodible Land (HEL) by the Natural Resource Conservation Service (NRCS).

These conservation measures could be adequate on certain soils in the Palo Verde area. For these lands, the NRCS noted that clod plowing would not be effective on the sandy textured soils predominant on the Palo Verde Mesa and would not be effective for long-term durations. Consequently, the NRCS reviewed these measures and suggested that a cover crop should be used to protect certain fallowed lands. The cover crop could require light irrigation during dry years that would need to be accounted for when determining the actual water conservation offset figure for a given plot of fallowed land.

Staff notes that absent a condition requiring the Applicant to implement erosion control recommendations of the NRCS, that there would not be any assurances that land fallowing would include proper Best Management Practices (BMPs) for erosion control, and therefore could lead to a significant adverse impact to soil resources. (FSA, p. 4.926 & 27)

Beyond the specific concern for erosion control measures, Staff believes the Final WCOP has not provided sufficient detail with regard to how it would be implemented, managed, monitored, reported, and verified. Some of Staff's specific concerns with the Applicant's proposed WCOP are highlighted as follows:

a) BMPs to prevent soil erosion of the fallowed lands have not been adequately addressed in the view of NRCS and staff, particularly for lands where there is no stubble residue (other than alfalfa, wheat, barley and similar crops) and in areas where clod plowing is not considered effective for coarse granular soil such as on the mesa.

b) Lands proposed for fallowing have not been identified, and thus cannot be verified that they have been irrigated within the past 5 years. Lands previously identified by the Applicant have since been withdrawn.

c) Fallowing lands that have been irrigated as infrequently as once in the last five years would only result in 20 percent of the water conservation that is needed and necessary to be achieved, and would cause a net increase in consumptive use of Colorado River water within both the PVID and the state.

d) Water needed to prevent soil erosion such as for establishing and maintaining vegetative cover or other soil surface treatment has not been identified in the proposed accounting method which assumes water will be conserved at a flat rate of 4.2 AFY per acre of land fallowed, regardless of the water that could be required for erosion control BMPs.

e) Management of the proposed WCOP does not include providing any historical or current records of irrigation to lands proposed for fallowing to verify the basis that water will be effectively conserved. During implementation of the WCOP it may be necessary to distinguish water conserved by the WCOP from other independent water conservation activities occurring within PVID's service area for which the WCOP could claim credit.

f) Monitoring, reporting, and annual verification of the results of the WCOP for demonstrating actual water conservation equivalent to BEP II's proposed annual use of 3,300 acre-feet per year has not been addressed. Although the Applicant has proposed to provide an annual accounting to USBR and PVID, it is not clear that these agencies will serve to verify results, or will have any authority to enforce compliance. Adequate oversight will ensure the success of the BEP II's WCOP and will avoid the problems that BEP I's WCOP has experienced.

Although staff believes the proposed BEP II WCOP in its current form is inadequate with respect to erosion control measures and its ability to accomplish water conservation, the USBR has indicated its acceptance of the BEP II WCOP. (FSA, p. 4.9-28)

But Staff also notes that USBR has previously reversed its position of acceptance with respect to the WCOP for BEP I. USBR questioned the validity and legality of BEP I's existing use of Colorado River water derived from groundwater due to its concerns that the BEP I WCOP is not acceptable, a position that reflects staff's view of the BEP I WCOP and that proposed for BEP II. The USBR's concern for BEP I stems from the realization that the offset lands claimed by BEP I did not have a recent history of irrigation.

The Colorado River Board of California (CRB), which believes that groundwater pumping is an unauthorized use, stated that for a water conservation offset program to be acceptable mitigation, actual water conservation would be necessary in an amount sufficient to offset the BEP II water use. Verification would be necessary to ensure that the amount of water unused for other reasons in the service area is not being credited against the water conservation offset program.

Staff suggests a CEQA-based condition prescribing a WCOP monitored by the Commission's CPM with additional erosion mitigation than offered by the Applicant and detailed accountability of lands fallowed or retired and water conserved. (FSA, p. 4.9-29)

Commission Discussion

The Applicant's WCOP is voluntary, since there are no applicable laws that require it and there are no CEQA environmental impacts which need to be mitigated through a WCOP. However, since the Applicant has proposed it as part of its project, the Commission has an interest in assuring that it is effective and not just window-dressing on the project. Plus, the Commission is responsible through CEQA to assure that the WCOP does not, itself, create adverse environmental impacts. The fact that the WCOP is voluntary does not exempt it from CEQA; for in reality, the entire power plant project is voluntary.

The Commission finds that the potential for erosion is a CEQA concern we need to address. The evidence supports a finding that clod tilling and stubble maintenance may not address all soil conditions on eligible farms. It appears that cover crops may be appropriate in some circumstances. Thus, the WCOP needs to include a more comprehensive menu of potential erosion mitigation measures and an ability to verify their effectiveness. The two Environmental Impact Reports for MWD/PVID and IID/San Diego have required such an array of mitigation as well.

The Commission is concerned that the WCOP actually produces a true offset of the project's water use. Although we wish it were not so, we see a potential that the WCOP, as drafted, may induce greater water use as landowners seek to be included in the marketplace of properties eligible for compensation. Our concern is that in the marketplace to select and compensate for *previously* irrigated lands, the WCOP may produce unintended consequences if not properly crafted. If the WCOP requires only that a parcel be irrigated for one of the last five years, there is nothing to prevent a landowner from resuming irrigation with high-quality PVID water on otherwise fallowed or semi-retired land for one year just to become eligible for the financial rewards of the WCOP. That is not the result sought by the Energy Commission, the USBR, the PVID, the Applicant or any other agency. True conservation will come only from fallowing or retiring of truly productive, irrigated farmland. An effective WCOP should not commence with farmland irrigated for only one year in five. For water conservation purposes, the one-year-in-five farmland should be our last choice, after more irrigated lands are taken. Based upon the farming practices discussed in this proceeding, productive farmland could appropriately be fallowed every other year. Thus, eligibility for this WCOP should not be less than productively irrigated lands for three of the last five years.

The Commission believes that a reasonable level of verification must accompany the WCOP, even though it is voluntary. Based upon the testimony, the Commission anticipates that more WCOPs will arise in the future to address shifting uses of Colorado River water. Whether these WCOPs are voluntary in anticipation of possible USBR regulation or are necessary for water transfers does not affect whether they should be verifiable. But if more WCOPs are on the horizon, and most particularly if they become mandatory, they should begin to have common elements, unless circumstances warrant exceptions. If the USBR begins to regulate groundwater use in the Colorado River aquifer, it may exercise the supremacy of federal law to formulate WCOP requirements. Therefore, we believe that verification of the water-conserving effectiveness of the WCOP on a CEQA basis should be performed with flexibility. There is not sufficient experience with WCOPs to know with certainty the level of scrutiny that is appropriate for the implementation of a WCOP. However, given California's critical interest in water conservation, such scrutiny cannot be lackadaisical. Thus, we include a CEQA-based condition requiring reasonable verification of water conservation.

CONDITION:

- ☑ To ensure no adverse environmental impacts, the WCOP shall include a comprehensive set of anti-erosion measures, criteria for farmlands eligible for the Program, and appropriate monitoring of verifiable water conservation. Condition: **WATER RES-1**
- ☑ The project owner shall install metering devices to record the daily amount of groundwater withdrawn by BEP II. Condition: **WATER RES - 2**

Well Interference

Significant well interference impacts occur when a project's pumping causes substantial and unacceptable declines in groundwater levels in existing nearby wells. Power plants are water-intensive operations when water is used for cooling. The magnitude of well interference is defined by the drawdown of groundwater levels, which radiates from the pumping well forming a cone of influence. The radial influence and depth of drawdown are determined by five factors: (1) the rate of pumping, (2) the duration of pumping, (3) the depth of the well intake screens, (4) the local aquifer parameters and (5) aquifer boundary conditions.

Aquifer field testing has been conducted in the vicinity of the proposed site at BEP I. BEP I conducted aquifer tests on both of the plant's production wells. The construction of monitoring wells, supply wells and irrigation wells and aquifer testing and retesting at the BEP I have provided detailed information on the aquifer conditions adjacent to the proposed project site. This testing provides the necessary data to evaluate well interference for BEP II. (FSA, p. 4.9-30)

Applicant

The Applicant provided an initial analysis in the AFC that evaluates well interference impacts that would be caused by project pumping. The Applicant stated that analysis included an evaluation of the impact of BEP II's pumping at average long-term pumping rates and short-term maximum pumping 4-month summer-peak demand rates. The Applicant based its analysis on the results of BEP I's first aquifer test for project well PW-2. Using a significance threshold of 5 feet drawdown on existing wells, the Applicant concluded that well interference caused by BEP II would have no significant adverse impact on nearby existing wells under long-term pumping conditions and short-term maximum pumping conditions. The nearest well identified by the Applicant, the Sun World well, would only experience 2.2 feet of drawdown, according to the analysis. The Applicant states that drawdown under short-term maximum pumping conditions would be negligible. (FSA, p. 4.9-30)

Staff

Staff has determined that BEP I's initial PW-2 aquifer test contained errors and was subsequently rejected by the Energy Commission. The BEP I project developer eventually performed successful tests on both its project wells, performed the analyses, and submitted reports that have been accepted by the Energy Commission. The Applicant has not revised its AFC well interference analysis for BEP II based on BEP I's approved test results.

In evaluating the significance of the impact of project pumping on nearby existing wells, it is important to recognize that all pumping causes drawdown and some degree of well interference. However, BEP II project pumping would cause drawdown that is greater than drawdown from agricultural or residential water use for comparable land use acreage. The water use-land use ratio for BEP II will be disproportionately higher than other existing water users on the Palo Verde Mesa, and, correspondingly, well interference from the BEP II could be disproportionately large. Currently, groundwater use in the mesa is very limited and well interference between existing wells would be very small. (FSA, p. 4.9-31)

Given the location of the proposed project, the location of existing wells that have been identified, and the results of the BEP I aquifer tests, there are three adverse impacts in nearby wells that may occur either alone or in combination, as a result of well interference caused by the BEP II groundwater use:

- A decline in the groundwater level requiring pump intake devices to be lowered to maintain efficient operation and to prevent damage to pumps;
- A decline in the groundwater level reducing the saturated interval from which the wells draw water; and/or
- An increase the pumping lift and the corresponding energy costs.

It should be noted that project well interference will only affect wells on the mesa. Water levels in wells located in the Palo Verde Valley would not be affected because drawdown from the BEP II wells would not extend past the PVID drains and unlined canals located at the toe of the mesa. These drains and canals would provide groundwater recharge to maintain groundwater levels within Valley wells.

Staff concluded that the significance criteria of 5-feet drawdown that was adopted for BEP I should be applied to BEP II. Likewise, the potential BEP II well interference can be mitigated by measures that restore the pumping capability of affected wells. (FSA, p. 4.9-36)

Commission Discussion
Both the Staff and Applicant agree that potential well interference can be mitigated. The Applicant requests that the Commission required the same well interference condition as in our BEP I Decision. Staff contends that there is well data that comes from the BEP I wells, which obviously did not exist when the BEP I condition was written. The new information from the BEP I well data shows that there will not be significant impacts in terms of capacity, and pumping lift costs would not be significant. Instead, the only potentially significant effect on a nearby well was from the two projects' pumping together. (8/1/05 RT 266:19 – 268:13) The Commission finds that the well interference mitigation should be updated from the former BEP I condition.

MITIGATION:

- ☑ If project groundwater pumping interferes with existing nearby wells, the Project Owner shall undertake measures to restore their pumping capability to pre-project levels. Condition: **WATER RES-3.**

Cumulative Impacts

Cumulative impacts are those that result from the incremental impacts of an action added to other past, present, and reasonably foreseeable future action, regardless of who is responsible for such actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.

Staff testified that *any* groundwater use by BEP II, as proposed, would cause a significant cumulative impact by decreasing water available to downstream Colorado River water users, due to the recharge of the aquifer in an amount equal to the pumped groundwater by Rannells Drain water that would otherwise return to the River. (8/1/05 RT 165:7 – 24) At one point, Staff testified that the decrease in available water would be significant because it potentially affected other users who have senior entitlements to Colorado River water. (FSA, p. 4.9A-54)

The Commission has previously discussed that the water from the Rannells Drain is insignificant tenths of a percent of the total return water. Moreover, it is undetectable with the measuring mechanisms of the PVID and the USBR. The fact that the hydrologic cycle includes the recharge of this groundwater aquifer from Rannells Drain water does not make that recharge a significant decrease in return flows to the Colorado River. The effect on downstream users is undetectable, and therefore there is no significant cumulative impact upon downstream users or in any other way.

Findings

With the implementation of the Conditions of Certification, as described in Water Resources, the project conforms to applicable laws related to water resources and all potential water resource impacts will be mitigated to insignificance.

CONDITIONS OF CERTIFICATION

WATER CONSERVATION OFFSET PLAN

WATER RES - 1: No later than 6 months after the beginning of site mobilization, the project owner shall provide a Water Conservation Offset Plan (WCOP) for review and comment by the Natural Resources Conservation Service (NRCS), US Bureau of Reclamation (USBR), Colorado River Board (CRB), and the Palo Verde Irrigation District (PVID), and for review and approval by the CPM. The CPM-approved WCOP shall remain in effect for the life of the project, unless superseded by a USBR-approved WCOP following assertion of federal jurisdiction over project groundwater pumping. The Final WCOP shall include the following:

a) Best Management Practices (BMPs) to prevent significant impacts resulting from soil erosion of the fallowed lands for all soil types.
b) Tabulation and corresponding maps of lands and the acreages proposed for fallowing and documentation to verify that they have been irrigated during at least 3 of the 5 most recent years.
c) An estimate of the water required and the methods planned to measure water use as needed to prevent soil erosion of fallowed agricultural lands, i.e., water used by a cover crop, etc., and the proposed means to include such use in the accounting method of actual water conserved.
d) Demonstration in the water conservation accounting method that BEP II will not be credited with other independent water conservation activities occurring within PVID's service area for which the WCOP has no effect.
e) Methodology for annual monitoring of the results of the WCOP demonstrating actual water conservation equivalent to BEP II's proposed annual water use of up to 3,300 acre-feet per year.

Verification: No later than 6 months after the beginning of site mobilization, the project owner shall submit a WCOP to NRCS, USBR, CRB and PVID for review and comment, and to the CPM for review and approval. In the annual compliance report, the project owner shall submit its annual accounting under the WCOP demonstrating the actual conservation of Colorado River water equivalent to BEP II's annual water use, and that erosion impacts from fallowed/retired land remain less than significant.

GROUNDWATER METERING

WATER RES - 2: The project owner shall install metering devices to record the daily amount of groundwater withdrawn by BEP II, separate and distinct from water use metered and reported by the BEP I project. The project owner shall prepare an annual water use summary coordinated with the annual compliance report for each well, which shall include:

- total water withdrawn by the project on a daily basis in gallons, and
- total water withdrawn by the project on an annual basis in acre-feet.

Following the first year, the annual water use summary shall also include:

- yearly range of water withdrawn for each well by the project and
- yearly average of water withdrawn for each well by the project.

Verification: As part of its annual compliance report, the project owner shall submit annual groundwater use data for each well as part of its annual water use summary to the CPM, the Palo Verde Irrigation District, and the United States Bureau of Reclamation for the life of the project.

WELL INTERFERENCE MITIGATION

WATER RES - 3: The project owner shall pay or reimburse all wells owners (at the affected well owner's option) whose wells are located on the Palo Verde Mesa, 3 miles or less from the midpoint of the BEP II - BEP I well field for a predicted cumulative decline in static groundwater level of 5 feet or more.

The project owner shall pay or reimburse the well owner an amount equal to the customary local cost of lowering the well owner's pump setting necessary to accommodate the decline in water level caused by the project, unless the project owner can demonstrate to the satisfaction of the CPM that the existing pump setting is sufficiently deep that lowering is unnecessary. In the event that the pump setting cannot be lowered without deepening the well, the project owner shall pay or reimburse the well owner an amount equal to the customary local cost of deepening the well. If the well cannot be deepened, the project owner shall pay or reimburse the well owner an amount equal to the customary local cost of installation of a new well.

The project owner shall provide evidence of notification describing the BEP II well interference mitigation requirements to all Palo Verde Mesa property owners whose land is located 3 miles or less from the midpoint of the BEP II - BEP I well field.

Verification: At least 90 days prior to well construction, the project owner shall provide evidence to the CPM that it has notified all Palo Verde Mesa property owners, whose land is located 3 miles or less from the midpoint of the BEP II – BEP I well field, regarding the BEP II well interference mitigation requirements. The project owner shall submit an annual compliance report describing compensation for pump lowering, pump replacement, or well deepening as well as any other well modifications undertaken to comply with the provisions of this condition to the CPM for review and approval.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

WATER RESOURCES

APPLICABLE LAW	DESCRIPTION
FEDERAL	
None	
STATE	
California Constitution, Article X, Section 2	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.
California Water Code, section 100, *et seq.*	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.
State Water Resources Control Board Policy 75 – 78; California Water Code, Sections 461 and 13552, and by Water Commission Resolution 77-1	SWRCB Resolution 75-58, discourages the use of fresh inland water for power plant cooling and prioritizes the source water of power plant cooling water: (1) wastewater discharge to the ocean, (2) ocean water, (3) brackish water from natural sources or irrigation return flow, (4) inland waste waters of low TDS, and, lastly, (5) other inland waters.
LOCAL	
City of Blythe, General Plan	Water resources goals and policies are intended to promote wise utilization of the Palo Verde Valley’s domestic, agricultural, and potable water sources and to encourage water conserving designs and technology to protect the valley’s vital water resources.

ALTERNATIVES – Summary of Findings

Alternative Sites	THE PRE-EXISTING GENERATING SITE IS PREFERABLE TO ANY ALTERNATIVE CEC Staff's analysis of alternative sites is predicated upon its conclusion that the proposed site has unmitigable water resource and aviation impacts. Based on Commission findings in this Decision that the use of groundwater does not cause significant water resources impacts and that aviation impacts can be mitigated to insignificance, the Commission concludes that an alternative site would not be preferable to the proposed site, and a more detailed alternative site analysis is not needed.
Alternative Design	NO ALTERNATIVE DESIGN IS PREFERABLE CEC Staff proposed an alternative cooling system using either dry cooling or agricultural return water from the Rannells Canal. The alternatives are unnecessary since the proposed project, using groundwater, does not cause an adverse environmental impact. Moreover, dry cooling in the Blythe desert setting is effectively infeasible to meet the project objectives. Rannells Drain water contains substantial amounts of "fresh" water, which is disfavored for power plant cooling.
Alternative Technology	NO ALTERNATIVE TECHNOLOGY IS PREFERABLE & FEASIBLE Alternative technologies include wind, solar, geothermal, and biomass. Solar technology requires a large amount of land, to produce the same amount of electricity. Geothermal resources are too far away. Biomass facilities are typically smaller than the capacity of the project and typically produce greater emissions than the equivalent gas-fired combustion turbine technology. Wind potentially creates numerous impacts and also requires a large amount of land with reliable and adequate wind energy resources.
"No Project" Alternative	THE "NO PROJECT" ALTERNATIVE IS INFERIOR TO PROPOSED PROJECT The "No Project" alternative causes older, less efficient power plants to be used to provide needed generation, consuming natural gas supplies less efficiently. The "no project" alternative would eliminate the expected economic benefits that the proposed project would bring to the local economy.

ALTERNATIVES – GENERAL

The Energy Commission's Power Plant Siting Regulatory Program is a "certified regulatory program" under CEQA. With regard to the "Alternatives" analysis required in a certified siting proceeding, the CEQA Guidelines (Cal. Code Regs., tit. 14, §15252) state that the environmental documentation shall include either:

- Alternatives to the activity and mitigation measures to avoid or reduce any significant or potentially significant effects that the project might have on the environment, or
- A statement that the agency's review of the project showed that the project would not have any significant or potentially significant effects on the environment and therefore no alternatives or mitigation measures are proposed to avoid or reduce any significant effects on the environment. This statement shall be supported by a checklist or other documentation to show the possible effects that the agency examined in reaching this conclusion."

The Energy Commission staff presented information in its Staff Assessment on the "feasibility of available site and facility alternatives to the Applicant's proposal that substantially lessen the significant adverse impacts of the proposal on the environment" (Cal. Code Regs., tit. 20, §1765). Staff also analyzed whether there are any feasible alternative designs or alternative technologies, including the "no project alternative," that may be capable of reducing or avoiding any potential impacts of the proposed project while achieving its major objectives.

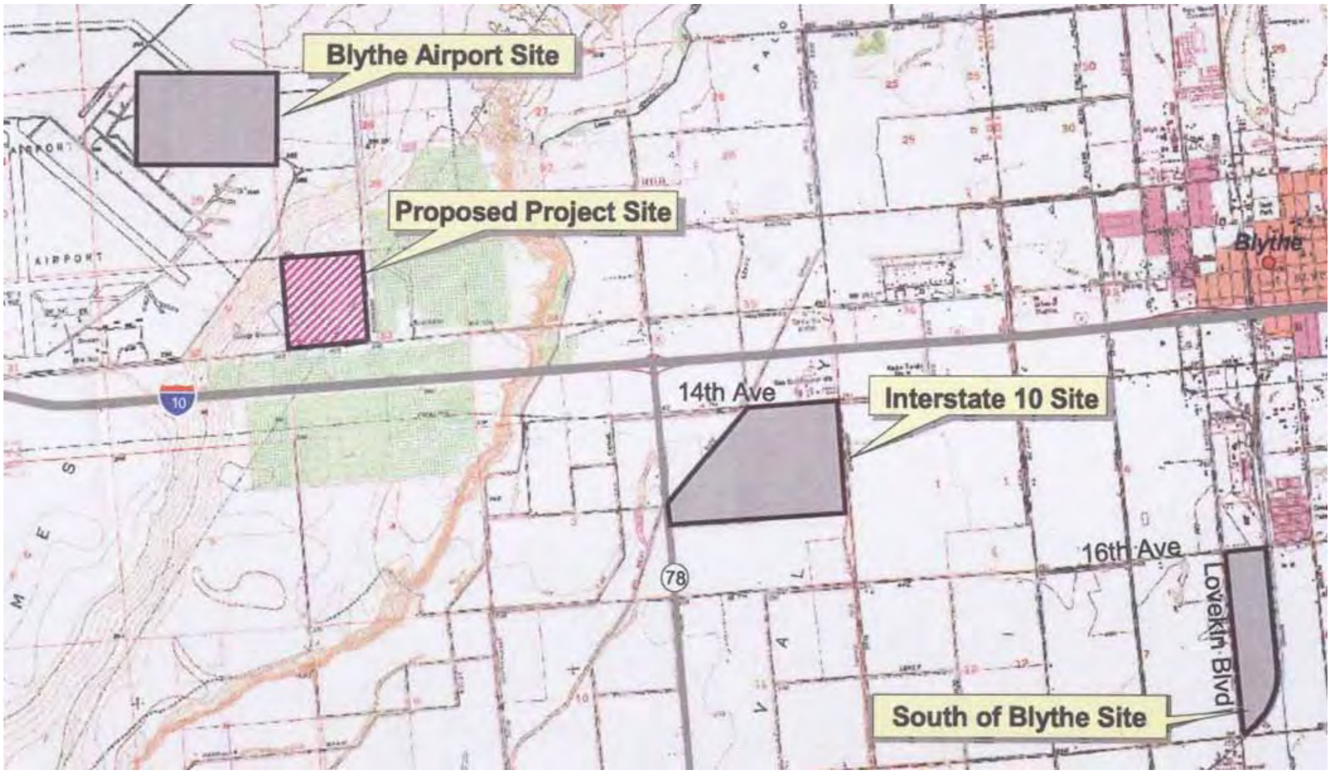
The Staff's undertook its Alternatives analysis based upon its view that the project causes potential adverse impacts on:

1. **TRAFFIC & TRANSPORTATION** due to flight safety concerns caused by the plumes from BEP I and BEP II,
2. **LAND USE** related to project interference with Blythe Airport operations,
3. **WATER RESOURCES** due to the use of groundwater hydrologically connected to the Colorado River, and
4. **TRANSMISSION SYSTEM ENGINEERING** due to the absence of final studies for a transmission outlet for project generation. (FSA, p. 6-1)

<u>Alternative Sites</u>

Consistent with the CEQA Guidelines, the consideration of alternative sites was guided by whether most project objectives could be accomplished at alternative sites and whether locating the project at an alternative site would substantially lessen any identified potential impacts of the project [Cal. Code Regs., tit. 14 §15126.6(a).]

Based on these and other concerns, Staff considered four alternative power plant sites. Three sites are in the Blythe area (Blythe Airport Site, Interstate 10 (I-10) Site, and South of Blythe Site), and one site is adjacent to the Devers Substation north of Palm Springs.



The California Environmental Quality Act requires that any alternative meet the project's objectives. The Applicant used the following site selection criteria for choosing the proposed site; however, Staff does not concur that all the criteria must be met when analyzing alternative sites. According to the AFC, the Applicant chose the proposed site for the following reasons:

1. The site is adjacent to BEP I;
2. The site is in close proximity to existing electrical transmission and natural gas facilities;
3. Sufficient land is available;
4. The site has environmental compatibility with an expected low impact on the environment, given its proximity to the industrial lands at the airport and BEP I, remoteness from residential areas, elevation above most populated areas, and low traffic conditions; and
5. The parcel is located in a designated corridor targeted for industrial development.

At the evidentiary hearings, the Applicant added that a project objective was to participate and fulfill the terms of Southern California Edison's Request for Offers. (Harvey, p. 2) Among other things, that would result in the facility's operating in an intermediate or load following configuration.

The construction of BEP II adjacent to the existing operating power plant (BEP I) offers the following advantages over any alternative: (1) reduction of the need to construct or develop redundant facilities or additional linear components; and (2) the BEP II power plant would be constructed on land already disturbed and evaluated for the original BEP I, for which desert tortoise mitigation has already been provided.

As differentiated from the Applicant, the Staff determined the project's objectives as:

1. Construction and operation of a merchant power plant with access to multiple markets;
2. Location near a substation and key infrastructure for natural gas, water supply and transmission lines; and
3. Generation of approximately 520 MW of electricity.

While the Applicant also included an objective of co-location with BEP I to minimize operational and maintenance costs, Staff felt it important to the analysis to explore other possible sites. Therefore, Staff did not utilize this objective when analyzing feasible alternatives. (FSA, p. 6-7)

Each alternative site was evaluated for its ability to reduce or eliminate the listed impacts, while not creating new significant unmitigable impacts of its own. Overall, Staff believed the four site alternatives offered some advantages and disadvantages in comparison to the proposed project. Staff's desire for new transmission studies would apply to all alternative sites. In Staff's view, significant biological resources impacts would be eliminated with Zero Liquid Discharge [ZLD], which the Applicant incorporated into the project after Staff's Alternatives analysis was prepared.

Further, Staff believes significant impacts would remain for all alternative sites in the issue areas of water resources, unless the project used dry cooling to obviate the need for groundwater for cooling. The alternative site adjacent to the Blythe Airport would have similar adverse aviation land use and traffic and transportation impacts as the project. All other potential impacts at the alternative sites would be reduced to less than significant levels with the implementation of mitigation measures. (FSA, p. 6-27)

According to Staff, the Interstate 10 Site has the best potential for reducing or eliminating the asserted significant environmental impacts of the proposed project, since this site is not near the airport and dry cooling could be used. Residences are within 0.45 miles of the alternative site, compared to 0,75 miles for the proposed site. (FSA, p. 6-18) Although there are potential noise and visual resource impacts associated with this site, Staff believes these impacts could be mitigated to a less than significant level. The I-10 site is on prime farmland, so mitigation would also be required to compensate for the loss of farmland. (FSA, p. 6-27) The South of Blythe Site would be less advantageous due to the proximity of residences to the site, but no significant impacts were identified at that site. The Devers Site would require rezoning, which is considered a significant impact. (FSA, p. 6-31)

The Applicant asserts that the Staff's Alternatives analysis is predicated upon its erroneous conclusion that the proposed site has unmitigable water resource and aviation impacts. Staff's preferred alternative, the I-10 site, would impact prime farmland, and require compensation to set aside other prime farmland in perpetuity. Instead, the Applicant testified that the proposed site has fewer impacts than the alternative sites selected by the Staff. (Harvey, p. 2)

Based on Commission findings in this Decision that the use of groundwater does not cause significant water resources impacts and that aviation impacts can be mitigated to insignificance, the Commission concludes that an alternative site would not be preferable to the proposed site, and a more detailed alternative site analysis is not needed.

Alternative Design

Alternative Cooling

Based upon its belief that the project's use of groundwater would contribute to a significant impact to the State's Colorado River water supply and its users, Staff suggested the alternative use of dry cooling or hybrid (wet/dry) cooling to eliminate or reduce water use. Staff acknowledged that dry cooling increases the potential for significant adverse impacts from thermal plumes to planes utilizing the nearby Blythe Airport, making it infeasible at the proposed site. (FSA, p. 6-10)

As discussed in detail in the **WATER RESOURCES** section, the Commission finds that dry cooling in the hot desert does not have the flexible cooling capacity to reliably operate the project as an intermediate load following facility as presently needed by the electricity marketplace. Electricity output and efficiency would be reduced. Additionally, dry cooling costs significantly more than wet cooling and produces more hazardous thermal plumes in this Blythe Airport environment. Lastly, dry cooling towers would be substantially more massive, creating more visual impact. Hybrid (wet/dry) cooling would have impacts falling between wet and dry cooling. Again, given that wet cooling does not create significant impacts, we conclude that hybrid cooling would likely be better than dry cooling, but not a reasonable alternative to wet cooling. Thus, the Commission finds that dry cooling and hybrid cooling are not preferable to the proposed wet cooling.

Alternative Technology

Reliance solely on natural gas fired power plants creates both environmental impacts and a dependence on a single energy source. Therefore, renewable resources are attractive power sources. Staff examined the principal renewable electricity generation technologies that could serve as alternatives to the proposed project and do not burn fossil fuels, and the potential for these facilities to be used instead of the proposed gas-fired plant. These technologies are geothermal, solar, hydroelectric, wind, and biomass. Each of these technologies could be attractive from an environmental perspective because of the absence or reduced level of air pollutant emissions. However, these technologies also can cause environmental impacts and have feasibility challenges in meeting project objectives.

Geothermal

Geothermal technologies use steam or high-temperature water (HTW) obtained from naturally occurring geothermal reservoirs to drive steam turbine/generators. The technology relies on either a vapor dominated resource (dry, super-heated steam) or a liquid-dominated resource to extract energy from the HTW. Geothermal is a commercially available technology, but it is limited to areas where geologic conditions result in high subsurface temperatures. There are no geothermal resources in the project vicinity, making this technology an infeasible alternative. (FSA, p. 6-24, 25)

<u>Biomass</u>
Biomass generation uses a waste vegetation fuel source such as wood chips or agricultural waste. The fuel is burned to generate steam. Biomass facilities generate substantially greater quantities of air pollutant emissions than natural gas burning facilities, though these emissions may be partially offset by the reduction in emissions from open-field burning of these fields. In addition, biomass plants are typically sized to generate less than 20 MW, which is substantially less than the capacity of the 520 MW BEP II project. In order to generate 520 MW, which is proposed for the BEP II, twenty-six 20 MW biomass facilities would be required. However, this number of power plants would have potentially significant environmental impacts of their own. (FSA, p. 6-25)

<u>Solar</u>
Currently, there are two types of solar generation available: solar thermal power and photovoltaic (PV) power generation. Solar thermal power generation uses high temperature solar collectors to convert the sun's radiation into heat energy, which is then used to run steam power systems. Solar thermal is suitable for distributed or centralized generation, but requires far more land than conventional natural gas power plants. Solar parabolic trough systems, for instance, use approximately five to eight acres to generate one megawatt.

Photovoltaic (PV) power generation uses special semiconductor panels to directly convert sunlight into electricity. Arrays built from the panels can be mounted on the ground or on buildings, where they can also serve as roofing material. Unless PV systems are constructed as integral parts of buildings, the most efficient PV systems require about four acres of ground area per megawatt of generation.

Solar resources would require large land areas in order to meet the project objective to generate 520 MW of electricity, *e.g.*, 2,000-plus acres.

While solar generation facilities do not generate problematic air emissions and have relatively low water requirements, there are other potential impacts associated with their use. Construction of solar thermal plants can lead to habitat destruction and visual impacts. PV systems can also have negative visual impacts, especially if ground-mounted. Furthermore, PV installations are highly capital intensive, and manufacturing of the panels generates some hazardous wastes.

Both solar thermal and PV facilities generate power during peak usage periods since they collect the sun's radiation during daylight hours. However, even though the use of solar technology may be appropriate for some portion of daily loads, solar energy technologies cannot provide full-time availability due to the natural intermittent availability of solar resources. Therefore, solar generation technology would not fully meet the project's goal, which is to provide load following power to meet demand and generate 520 MW of electricity. (FSA, p. 6-25)

Wind

Wind carries kinetic energy that can be utilized to spin the blades of a wind turbine rotor and an electrical generator, which then feeds alternating current (AC) into the utility grid. Most state-of-the-art wind turbines operating today convert 35 to 40 percent of the wind's kinetic energy into electricity. Modern wind turbines represent viable alternatives to large bulk power fossil power plants as well as small-scale distributed systems. The range of capacity for an individual wind turbine today ranges from 400 watts up to 3.6 MW. California's 1,700 MW of wind power represents 1.5 percent of the state's electrical capacity.

Although air emissions are significantly reduced or eliminated for wind facilities, they can have significant visual effects. Also, wind turbines can cause bird mortality (especially for raptors) resulting from collision with rotating blades.

Wind resources would require large land areas in order to generate 520 MW of electricity. Wind "farms" generally require between 5 and 17 acres to generate one megawatt (resulting in the need for between 2,600 and 8,840 acres to generate 520 MW). California has a diversity of existing and potential wind resource regions that are near load centers such as San Francisco, Los Angeles, San Diego and Sacramento. However, wind energy technologies cannot provide full-time availability due to the natural intermittent availability of wind resources. Therefore, wind generation technology would not meet the project's goal, which is to provide load following power to meet demand and generate 520 MW of electricity. (FSA, p. 6-26)

Hydroelectric Power

While hydropower does not require burning fossil fuels and may be available, this power source can cause significant environmental impacts primarily due to the inundation of many acres of potentially valuable habitat and the interference with fish movements during their life cycles. As a result of these impacts, it is extremely unlikely that new hydropower facilities could be developed and permitted in California within the next several years. (FSA, p. 6-26)

Conclusion

The renewable technologies discussed above have the advantage of not requiring the burning of fossil fuels and avoiding the environmental and resource impacts associated with natural gas-fired power. However, these technologies also have the potential to cause significant land use, biological, cultural resource, and visual impacts. Plus, they have substantial cost and regulatory hurdles to overcome before they can provide substantial amounts of power. In summary, these alternatives are not preferable because (a) they cannot feasibly meet project objectives, and (b) they have the potential to create potentially significant environmental effects. (FSA, p. 6-27)

"No Project" Alternative

CEQA Guidelines and Energy Commission regulations require consideration of the "no project" alternative. This alternative assumes that the project is not constructed, and compares that scenario to the proposed project. A determination is made whether the "no project" alternative is superior, equivalent, or inferior to the proposed project.

In the absence of the BEP II project, two types of events are likely to occur. First, other power plants could be constructed in California to serve the demand that could be met with the BEP II project. Second, new transmission lines could be constructed to import electricity generated out-of-state into California markets. For example, SCE's proposed DPV2 project would import about 1,200 MW of existing generation capacity from Arizona into California. While this additional power would replace the 520 MW that would have been generated at BEP II, it would also serve to increase California's reliance on out-of-state generation. (FSA, p. 6-22)

Unless and until the Desert Southwest Transmission Project (DSWTP) is constructed, the BEP II project has no current viable transmission connection to the grid for its full generating capacity, and as a result it may not be able to achieve the potential benefits of contributing to California's generating resources, increasing competition, and helping to form a more reliable electric system. The DSWTP is under active regulatory review. If this facility were not constructed, the proposed site would remain as open space, and additional power to meet both the Applicant's objectives and the State's needs would not be available from this project.

With a viable transmission connection to California markets, the proposed facility could also serve to replace older, inefficient facilities. However, if the "no project" alternative were selected, the construction and operational impacts of the BEP II would not occur. (FSA, p. 6-23)

The Commission finds the "No Project" alternative is not superior to the proposed project. The "no project" alternative will not meet need for new reliable electricity and would lead to the continued use of less efficient existing, older power plants. The "no project" alternative would also cause the loss of local economic benefits. Therefore, the "no project" alternative is inferior to the proposed project.

Findings

The Commission has analyzed alternatives to the project design and related facilities, alternative technologies, and the "no project" alternative. Developing the project at an alternative site would defeat a core goal and objectives of the project. An alternative site would not substantially lessen the potential impacts of the project, which are mitigated to insignificance by the Conditions of Certification. The Commission does not believe that alternative designs are feasible or offer a valuable reduction in impacts. The Commission does not believe that alternative technologies present feasible alternatives to the proposed project. The "no project" alternative will not meet need for new reliable electricity and would lead to the continued use of less efficient existing, older power plants. The "no project" alternative would also cause the loss of local economic benefits. Therefore, the "no project" alternative is inferior to the proposed project.

EFFICIENCY – Summary of Findings

Local/Regional Energy Supplies	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** The project will combust natural gas as its sole fuel. The El Paso Natural Gas Company supply infrastructure is extensive, offering access to vast reserves of gas. It is therefore highly unlikely that the project could pose an adverse effect on energy supplies and resources.
Energy Consumption Rate	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** The project will employ state-of-the-art technology, with an overall fuel efficiency of between approximately 55 and 58 percent. While it will consume substantial amounts of natural gas, 84,400 MMBtu per day, it will do so in the most efficient manner practicable.

EFFICIENCY - GENERAL

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" (Cal. Code Regs., tit. 14, §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 wasteful, inefficient and unnecessary consumption of energy (Cal. Code Regs., tit. 14, § 15000 et seq., Appendix F).

The Applicant proposes to construct and operate the 520 MW (nominal gross output) combined cycle, merchant BEP II power plant to generate load following power, selling energy to the power market. (FSA, p. 5.3-1)

The BEP II will consist of two Siemens Westinghouse V84.3a 170 MW F-class combustion gas turbines with a chilled water inlet air cooling system, two multi-pressure heat recovery steam generators (HRSGs) with duct burners, and one single 3-pressure, reheat, condensing steam turbine (ST) generator producing a maximum of 180 MW, arranged in a two-on-one combined cycle train, totaling approximately 520 MW. The gas turbines and HRSGs will be equipped with dry low-NOx combustors and selective catalytic reduction to control air emissions. Natural gas will be delivered by the existing El Paso Natural Gas Company gas distribution system through a new pipeline connection to the completed Blythe Energy Project I gas supply system. (FSA, p. 5.3-1-2)

Local/Regional Energy Supplies

Natural gas for the BEP II will be supplied from the existing El Paso Natural Gas Company system via a new pipeline connection to the approved BEP I gas supply system. The system is capable of delivering the required quantity of gas to the BEP II. The El Paso natural gas supply represents a reliable source of natural gas for this project. It is therefore highly unlikely that the project could pose a substantial increase in demand for natural gas in California. There is no real likelihood that the BEP II will require the development of additional energy supply capacity. (FSA, p. 5.3-2-3)

Energy Consumption Rate

Any power plant large enough to fall under Energy Commission siting jurisdiction will consume large amounts of energy. Under normal conditions, the BEP II will burn natural gas at a nominal rate of 84,400 MMBtu per day. This is a substantial rate of energy consumption, and holds the potential to impact energy supplies. Under expected project conditions, electricity will be generated at a full load efficiency of between approximately 55 and 58 percent. This efficiency level compares favorably to the average fuel efficiency of a typical utility company baseload power plant at approximately 35 percent. (FSA, p. 5.3-2)

The project configuration (combined cycle) and generating equipment (F-class gas turbines) represent the most efficient feasible combination to satisfy the project objectives. The two-train CT/HRSG configuration also allows for high efficiency during unit turndown because one CT can be shut down, leaving one fully loaded, efficiently operating CT instead of having two CTs operating at an inefficient 50 percent load. This offers an efficiency advantage over the larger machines during unit turndown. There are no alternatives that could significantly reduce energy consumption. Therefore, the BEP II will not constitute a significant adverse impact on energy resources. (FSA, p. 5.3-5-6)

Cumulative Impacts

BEP I presently operates a nearby power plant project that holds the potential for cumulative energy consumption impacts when aggregated with the project. There are no other nearby projects that could result in cumulative energy impacts.

Construction and operation of the project will not bring about indirect impacts, in the form of additional fuel consumption, that would not have occurred but for the project. The older, less efficient power plants consume more natural gas to operate than the new, more efficient plants such as the BEP II. Since natural gas will be burned by the power plants that are most competitive in the market, the most efficient plants will run the most. The high efficiency of the proposed BEP II should allow it to compete favorably, replacing less efficient power generating plants in the market, and therefore not adversely impacting and perhaps even reducing the cumulative amount of natural gas consumed for power generation. (FSA, p. 5.3-6)

Finding

Without Conditions of Certification, the project conforms to applicable laws related to efficiency; and other Conditions of Certification of this Decision will mitigate to insignificance all potential adverse impacts regarding the efficient consumption of energy.

CONDITIONS OF CERTIFICATION

None.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

EFFICIENCY

APPLICABLE LAW	DESCRIPTION
STATE	
Title 14, California Code of Regulations, § 15126.4(a)(1)	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" (Cal. Code Regs., tit. 14, § 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 wasteful, inefficient and unnecessary consumption of energy (Cal. Code Regs., tit. 14, § 15000 et seq., Appendix F).

FACILITY DESIGN – Summary of Findings and Conditions

Engineering - General	COMPLIES WITH APPLICABLE LAWS & REGULATIONS
	To protect public health and safety as well as the viability of the project, the applicable power plant equipment, pipelines, and other non-transmission line structures shall be designed and constructed in accordance with the 2001 California Building Standards Code, or its successor. The Chief Building Official shall review and approve the relevant design criteria and plans submitted by the Project Owner and conduct all necessary inspections. **CONDITIONS:** ☑ The Project Owner shall construct the project using the most recent California Building Standards Code with the oversight and approval of the Chief Building Official; shall assign California registered engineers to the project; and shall pay necessary in-lieu permit fees. Conditions: **GEN-1** through **GEN-8**.
Engineering Geology	COMPLIES WITH APPLICABLE LAWS & REGULATIONS
	As described in **GEOLOGY**, seismic zone 3 conditions at the project site require the preparation of an Engineering Geology Report pursuant to the California Building Standards Code to characterize the geologic conditions. During site grading, a designated Engineering Geologist shall monitor for any adverse soil or geologic conditions. Conditions: **GEN-1, CIVIL-1** and **CIVIL-2.** **CONDITIONS:** ☑ The Project Owner shall prepare an Engineering Geology Report pursuant to the California Building Standards Code to fully describe the geologic conditions of the power plant site and, if necessary, shall modify plans to address adverse soil or geologic conditions. Conditions: **GEN-1, CIVIL-1** & **CIVIL-2**.

Civil Engineering	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** To ensure erosion and sedimentation control, among other things, the Project Owner shall submit a site grading and drainage plan. (See also **WATER QUALITY-2**) To ensure proper conditions for foundations and other features, any adverse soil or geologic conditions shall be reported and corrected during site grading. **CONDITIONS:** ☑ The Project Owner shall submit grading plans and erosion/ sedimentation control plans, perform inspections and submit as-built plans for approval. Conditions: **CIVIL-1** & **CIVIL-4**. ☑ If appropriate, the resident engineer shall stop construction if unknown, adverse geologic conditions are encountered. Condition: **CIVIL-2.**
Structural Engineering	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** Major structures and equipment are those necessary for power production, costly or time-consuming to repair, those used for the storage of hazardous materials, or those that may become potential health and safety hazards if not constructed to applicable engineering LORS. The AFC lists the design criteria essential to ensuring that the project is designed in a manner that protects the environment and public health and safety. **CONDITIONS:** ☑ For earthquake safety of major structures, foundations, supports, anchorages, and tanks, the Project Owner will submit appropriate lateral force calculations, designs and plans to the Chief Building Official for approval. In addition, to ensure the safety of storage tanks, some of which contain hazardous materials, the Project Owner will submit plans and specifications to the Chief Building Official for approval. Conditions: **STRUC-1** through **STRUC-4**.

Mechanical Engineering	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** The mechanical systems include not only the power train with its major components but also water and wastewater treatment facilities, pressure vessels, piping systems and pumps, storage tanks, air compressors, fire protection systems, heating and ventilation, and water and sewage. The AFC lists and describes the mechanical codes and design criteria applicable to these systems. **CONDITIONS**: ☑ To ensure the safety of piping and pressure vessels, some of which transport or store hazardous materials, the Project Owner will submit plans and specifications to the Chief Building Official for approval. Heating and air conditioning equipment, as well as plumbing, will be reviewed and inspected by the Chief Building Official. Conditions: **MECH-1** through **MECH-4**.
Electrical Engineering	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** Major electrical features of the project, other than transmission, include generators, power control wiring, protective relays, grounding systems, and site lighting. The AFC lists and describes the electrical codes and design criteria applicable to these systems. **CONDITIONS**: ☑ For electric systems or components of 480 volts or higher, Project Owner shall submit plans to the Chief Building Official for approval. Condition: **ELEC-1.**

FACILITY DESIGN – GENERAL

The Warren-Alquist Act requires the commission to "prepare a written decision….which includes:

(a) Specific provisions relating to the manner in which the proposed facility is to be designed, sited, and operated in order to protect environmental quality and assure public health and safety, [and]

(d)(1) Findings regarding the conformity of the proposed site and related facilities…with public safety standards…and with other relevant local, regional, state and federal standards, ordinances, or laws…" (Pub. Resources Code, § 25523).

Facility Design encompasses the civil, structural, mechanical and electrical engineering aspects of the project. The Facility Design analysis verifies that the project has been described in sufficient detail to provide reasonable assurance that it can be designed and constructed in accordance with all applicable laws and regulations, and in a manner that protects environmental quality and assures public health and safety.

This analysis also examines whether special design features should be considered during final design to deal with conditions unique to the site that could influence public health and safety. This analysis further identifies the design review and construction inspection process and establishes conditions of certification that will be used to ensure compliance with applicable laws and regulations and any special design requirements.

Engineering - General

Under Section 104.2 of the California Building Code (CBC), the building official is authorized and directed to enforce all the provisions of the CBC. For all energy facilities certified by the Energy Commission, the Energy Commission is the building official and has the responsibility to enforce the code. In addition, the Energy Commission has the power to render interpretations of the CBC and to adopt and enforce rules and supplemental regulations to clarify the application of the CBC's provisions.

The Energy Commission's design review and construction inspection process is developed to conform to CBC requirements and ensure that all facility design conditions of certification are met. As provided by Section 104.2.2 of the CBC, the Energy Commission appoints experts to carry out the design review and construction inspections and act as a delegated Chief Building Officer (CBO) on behalf of the Energy Commission. These delegate agents typically include the local building official and/or independent consultants hired to cover technical expertise not provided by the local official. The Project Owner, through permit fees as provided by CBC Sections 107.2 and 107.3, pays the costs of the reviews and inspections. While building permits in addition to the Energy Commission certification are not required for this project, the Project Owner pays in-lieu permit fees, consistent with CBC Section 107, to cover the costs of reviews and inspections.

The Energy Commission has developed Conditions of Certification to ensure compliance with applicable laws and regulations and protection of the environment and public health and safety. Some of these conditions address the roles, responsibilities and qualifications of the Project Owner's engineers responsible for the design and construction of the project. Engineers responsible for the design of the civil, structural, mechanical, and electrical portions of the project are required to be registered in California, and to sign and stamp each submittal of design plans, calculations, and specifications submitted to the CBO. These conditions require that no element of construction subject to CBO review and approval proceed without prior approval from the CBO. They also require that qualified special inspectors be assigned to perform or oversee special inspections required by the applicable LORS.

While the Energy Commission and the delegated CBO have the authority to allow some flexibility in scheduling construction activities, these conditions are written to require that no element of construction of permanent facilities subject to CBO review and inspection, which is difficult to reverse or correct, may proceed without prior approval of plans from the CBO. For those elements of construction that are not difficult to reverse and are allowed to proceed without approval of the plans, the Project Owner shall have the responsibility to fully modify those elements of construction to comply with all design changes that result from the CBO's subsequent plan review and approval process.

CONDITIONS:

- ☑ The Project Owner shall construct the project using the most recent California Building Standards Code with the oversight and approval of the Chief Building Official; shall assign California registered engineers to the project; and shall pay necessary in-lieu permit fees. Conditions: **GEN-1** through **GEN-8**.

Engineering Geology

As described in **GEOLOGY**, seismic zone 3 conditions at the project site require the preparation of an Engineering Geology Report to characterize the geologic conditions.

CONDITIONS:

- ☑ The Project Owner shall prepare an Engineering Geology Report pursuant to the California Building Standards Code to fully describe the geologic conditions of the power plant site and, if necessary, shall modify plans to address adverse soil or geologic conditions. Conditions: **GEN-1, CIVIL-1** & **CIVIL-2**.

Civil Engineering

The power plant and related facilities shall be designed to meet the seismic requirements of the latest edition of the California Building Standards Code.

CONDITIONS:

- ☑ The Project Owner shall submit grading plans and erosion/sedimentation control plans, perform inspections and submit as-built plans for approval. Conditions: **CIVIL-1, CIVIL-3** & **CIVIL-4**.
- ☑ If appropriate, the resident engineer shall stop construction if unknown, adverse geologic conditions are encountered. Condition: **CIVIL-2**.

Structural Engineering

Major structures, systems and equipment are defined as those necessary for power production and are costly to repair or replace, or that require a long lead time to repair or replace, or those used for the storage, containment, handling of hazardous or toxic materials, or those that may become potential health and safety hazards if not constructed according to the applicable engineering LORS. The AFC lists the civil, structural, mechanical and electrical design criteria and demonstrates the likelihood of compliance with applicable LORS, all of which is essential to ensuring that the project is designed in a manner that protects the public health and safety.

The project will be designed and constructed consistent with the 2001 edition of the California Building Standards Code (CBSC), and other applicable codes and standards in effect at the time design and construction of the project actually commence. In the event the design of project is submitted to the Chief Building Official (CBO) for review and approval when the successor to the 2001 CBSC is in effect, the 2001 CBSC provisions, identified herein, shall be replaced with the applicable successor provisions.

The procedures and limitations for the seismic design of structures by the 2001 CBC are determined considering seismic zoning, site characteristics, occupancy, structural configuration, structural system and height. Different design and analysis procedures are recognized in the 2001 CBC for determining seismic effects on structures.

CONDITIONS:

- ☑ For earthquake safety of major structures, foundations, supports, anchorages, and tanks, the Project Owner will submit appropriate lateral force calculations, designs and plans to the Chief Building Official for approval. In addition, to ensure the safety of storage tanks, some of which contain hazardous materials, the Project Owner will submit plans and specifications to the Chief Building Official for approval. Conditions: **STRUC-1** through **STRUC-4**.

<u>Mechanical Engineering</u>

The AFC lists and describes the mechanical codes, standards and design criteria that will be employed in project design documents, procurement specifications and contracts. Design work will be performed in accordance with the appropriate LORS. This approach will assure the project's mechanical systems are designed to the appropriate codes and standards. Condition: **MECH-1** through **MECH-3.**

CONDITIONS:

- ☑ To ensure the safety of piping and pressure vessels, some of which transport or store hazardous materials, the Project Owner will submit plans and specifications to the Chief Building Official for approval. Heating and air conditioning equipment, as well as plumbing, will be reviewed and inspected by the Chief Building Official. Conditions: **MECH-1** through **MECH-3**.

<u>Electrical Engineering</u>

Major electrical features of the project, other than transmission, include generators, power control wiring, protective relaying, grounding system, cathodic protection system and site lighting. The AFC lists and describes the electrical codes, standards and design criteria that will be employed in project design documents, procurement specifications and contracts.

CONDITIONS:

- ☑ For electric systems or components of 480 volts or higher, the Project Owner shall submit plans to the Chief Building Official for approval. Conditions: **ELEC-1**.

<u>Finding</u>

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to facility design and related engineering fields.

CONDITIONS OF CERTIFICATION

(All transmission facilities (lines, switchyards, switching stations and substations) are handled in Conditions of Certification in the **TRANSMISSION SYSTEM ENGINEERING** section of this Decision.)

GEN-1 The project owner shall design, construct and inspect the project in accordance with the 2001 California Building Standards Code (CBSC) (also known as Title 24, California Code of Regulations), which encompasses the California Building Code (CBC), California Building Standards Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and all other applicable engineering LORS in effect at the time initial design plans are submitted to the CBO for review and approval. (The CBSC in effect is that edition that has been adopted by the California Building Standards Commission and published at least 180 days previously.)

In the event that the initial engineering designs are submitted to the CBO when a successor to the 2001 CBSC is in effect, the 2001 CBSC provisions identified herein 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 shall clearly specify that all work performed and materials supplied on this project are to comply with the applicable codes listed above.

<u>Verification:</u> Within 30 days after execution of any contract or subcontract, the project owner shall submit to the CPM a copy of that portion of the contract or subcontract containing language specifying that work under that contract or subcontract shall comply with the applicable codes listed in this Condition of Certification. Within

30 days after receipt of the Certificate of Occupancy, the project owner shall submit to the CPM a statement of verification, signed by the responsible 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 [2001 CBC, Section 109 – Certificate of Occupancy].

GEN-2 Prior to submittal of the initial engineering designs for CBO review, the project owner shall furnish to the CPM and to the CBO a schedule of facility design submittals, a Master Drawing List and a Master Specifications List. 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 when requested.

Verification: At least 60 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO and to the CPM the schedule, the Master Drawing List and the Master Specifications List of documents to be submitted to the CBO for review and approval. These documents shall be the pertinent design documents for the major structures and equipment listed in **Facility Design Table 1** 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.

Table 1: Major Structures and Equipment List

Equipment/System	**Quantity (Plant)**
Combustion Turbine (CT) Foundation and Connections	2
Combustion Turbine Generator Foundation and Connections	2
Steam Turbine (ST) Foundation and Connections	1
Steam Turbine Generator Foundation and Connections	1
Auxiliary Transformer Foundation and Connections	2
CT Inlet Air Plenum Structure, Foundation and Connections	2
Heat Recovery Steam Generator (HRSG) Structure, Foundation and Connections	2
HRSG Stack Structure, Foundation and Connections	2
Cooling Tower Structure, Foundation and Connections	1
Boiler Feed Pump Foundation and Connections	3
Condensate Extraction Pump Foundation and Connections	3
Circulating Water Pump Foundation and Connections	2
Steam Surface Condensers Foundation and Connections	2
Condenser Evacuation Pump Foundation and Connections	2
Turbine Hall Overhead Crane	1
Continuous Emission Monitoring System Structure, Foundation and Connections	2
Ammonia Storage System Foundation and Connections	1
Circulating Water System Dosing Foundation and Connections	1
Water Steam Cycle Dosing Foundation and Connections	1
High, Intermediate and Low Pressure Steam Systems	1 Lot
Reheat Steam System	1 Lot
Condensate and Feed Systems	1 Lot
Water Treatment System Brine Concentrator Foundation and Connections	1

Equipment/System	**Quantity (Plant)**
Water Treatment System Demineralizer Foundation and Connections	1
Raw Water Storage Tank Foundation and Connections	1
Demineralized Water Storage Tank Foundation and Connections	1
Fuel Gas Heater Foundation and Connections	2
Fuel Gas Scrubbing and Regulating System Foundation and Connections	1
Fire Protection System Pumps Foundation and Connections	2
Workshop/Storage Building Structures, Foundation and Connections	1
Fire Pump House Foundation and Connections	1
Control Room Building Structures, Foundation and Connections	1
Boiler Feedwater Pump House Structures, Foundation and Connections	1
Secondary Unit Substation/Transformer	2
Combustion Turbine Electrical/Control Center	2
Steam Turbine Electrical/Control Center	2
Air Compressor Foundation and Connections	2
CT Static Starter Skid Foundation and Connections	2
Switchgear Equipment Building Structure, Foundation and Connections	2
CT Generator Step-up Transformer Foundation and Connections	2
ST Generator Step-up Transformer Foundation and Connections	1
Air Receiver Foundation and Connections	1
Air Dryer Foundation and Connections	1
Closed Cycle Cooling Water Heat Exchanger Foundation and Connections	2
Closed Cycle Cooling Water Pump Foundation and Connections	2
Inlet Air Chilling (or Evaporative Cooling) Skid Foundation and Connections	2
Water Treatment Systems Skid Foundation and Connections	1 Lot
Potable Water Systems	1 Lot
Drainage Systems (including sanitary drain and waste)	1 Lot
High Pressure and Large Diameter Piping	1 Lot
HVAC and Refrigeration Systems	1 Lot
Temperature Control and Ventilation Systems (including water and sewer connections)	1 Lot
Building Energy Conservation Systems	1 Lot
Substation/Switchyard, Buses and Towers (Excluding Buck Blvd. Substation)	1 Lot
Electrical Duct Banks	1 Lot

GEN-3 The project owner shall make payments to the CBO for design review, plan check and construction inspection based upon a reasonable fee schedule to be negotiated between the project owner and the CBO based on a CPM approved agreement. These fees may be consistent with the fees listed in the 2001 CBC [Chapter 1, Section 107 and Table 1-A, Building Permit Fees; Appendix Chapter 33, Section 3310 and Table A-33-A, Grading Plan

Review Fees; and Table A-33-B, Grading Permit Fees], 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 as otherwise agreed by the project owner and the CBO. Payments to the CBO shall in no way affect or diminish the independence of the CBO.

<u>Verification:</u> 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 the applicable fees have been paid. The project owner shall provide a copy of the payment agreement to the CPM for review and approval prior to execution.

GEN-4 Prior to the start of rough grading, the project owner shall assign a California registered architect, structural engineer or civil engineer, as a resident engineer (RE), to be in general responsible charge of the project [Building Standards Administrative Code (Cal. Code Regs., tit. 24, § 4-209, Designation of Responsibilities)].

The RE may delegate responsibility for portions of the project to other registered engineers. Registered mechanical and electrical engineers may be delegated responsibility for mechanical and electrical portions of the project, respectively. A project may be divided into parts, provided each part is clearly defined as a distinct unit. Separate assignment of general responsible charge may be made for each designated part. The RE shall:

1. Monitor construction progress of work requiring CBO design review and inspection to ensure compliance with LORS;
2. Ensure that construction of all the facilities subject to CBO design review and inspection conforms in every material respect to the applicable LORS, these Conditions of Certification, approved plans, and specifications;
3. Prepare documents to initiate changes in the approved drawings and specifications when directed by the project owner or as required by conditions on the project;
4. Be responsible for providing the project inspectors and testing agency(ies) with complete and up-to-date set(s) 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 as not conforming to the approved plans and specifications.

The RE shall have the authority to halt construction and to require changes or remedial work, if the work does not conform to applicable requirements.

If the RE or the delegated engineers are reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.

<u>Verification:</u> At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the resume and registration number of the RE and any other delegated engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the RE and other delegated engineer(s) within five days of the approval.
If the RE or the delegated engineer(s) are 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-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) a civil engineer; B) a soils engineer, or a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering; and C) 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: D) a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; E) a mechanical engineer; and F) an electrical engineer. [California Business and Professions Code section 6704 et seq., and sections 6730, 6731 and 6736 requires state registration to practice as a civil engineer or structural engineer in California.]

The tasks performed by the civil, mechanical, electrical or structural 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 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 [2001 CBC, Section 104.2, Powers and Duties 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. The civil engineer shall:

1. Review the Foundation Investigations Report, Geotechnical Report or Soils Report 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 design, stamp, and sign all plans, calculations and specifications for proposed site work, civil works and related facilities requiring design review and inspection by the CBO. At a minimum, these include:

grading, site preparation, excavation, compaction, construction of secondary containment, foundations, erosion and sedimentation control structures, drainage facilities, underground utilities, culverts, site access roads and sanitary sewer systems; and

3. Provide consultation to the RE during the construction phase of the project and when necessary, recommend changes in the design of the civil works facilities and changes in the construction procedures.

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 Report, Geotechnical Report or Soils Report containing field exploration reports, laboratory tests and engineering analysis detailing the nature and extent of the soils that may be susceptible to liquefaction, rapid settlement or collapse when saturated under load [2001 CBC, Appendix Chapter 33, Section 3309.5, Soils Engineering Report; Section 3309.6, Engineering Geology Report; and Chapter 18, Section 1804, Foundation Investigations];
3. Be present, as required, during site grading and earthwork to provide consultation and monitor compliance with the requirements set forth in the 2001 CBC, Appendix Chapter 33; Section 3317, Grading Inspections (depending on the site conditions, this may be the responsibility of either the soils engineer or engineering geologist or both); and
4. Recommend field changes to the civil engineer and RE.

This engineer shall be authorized to halt earthwork and to require changes if site conditions are unsafe or do not conform to predicted conditions used as a basis for design of earthwork or foundations [2001 CBC, section 104.2.4, Stop orders].

The engineering geologist shall:

1. Review all the engineering geology reports and prepare 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 2001 CBC, Appendix Chapter 33; Section 3317, Grading Inspections (depending on the site conditions, this may be the responsibility of either the soils engineer or engineering geologist or both).

The structural or civil engineer shall:

1. Be directly responsible for the design of the proposed structures and equipment supports;
2. Provide consultation to the RE during design and construction of the project;

3. Monitor construction progress to ensure compliance with engineering LORS;
4. Evaluate and recommend necessary changes in design; and
5. Prepare and sign all major building plans, specifications and calculations.

E. The mechanical engineer shall be responsible for, and sign and stamp a statement with, each mechanical submittal to the CBO, stating that the proposed final design plans, specifications, and calculations conform to all of the mechanical engineering design requirements set forth in the Energy Commission's Decision.

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.

<u>Verification:</u> At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of the responsible civil engineer, soils (geotechnical) engineer and engineering geologist assigned to the project.

At least 30 days (or project owner and CBO approved alternative timeframe) 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 structural 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 2001 CBC, Chapter 17 [Section 1701, Special Inspections; Section 1701.5, Type of Work (requiring special inspection)]; and Section 106.3.5, Inspection and observation program. The special inspector shall:

2. 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;
3. Observe the work assigned for conformance with the approved design drawings and specifications;
4. Furnish inspection reports to the CBO and RE. All discrepancies shall be brought to the immediate attention of the RE for correction, then, if

uncorrected, to the CBO and the CPM for corrective action [2001 CBC, Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector]; and

5. Submit a final signed report to the RE, CBO, and CPM, stating whether the work requiring special inspection was, to the best of the inspector's knowledge, in conformance with the approved plans and specifications and the applicable provisions of the applicable edition of the CBC.

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).

Verification: At least 15 days (or project owner and CBO approved alternative timeframe) 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 the corrective action required [2001 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall be submitted to the CBO for review and approval. The discrepancy documentation shall reference this Condition of Certification and, if appropriate, the 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 the CBO's approval.

GEN-8 The project owner shall obtain the CBO's final approval of all completed work that has undergone CBO design review and approval. The project owner shall request the CBO to inspect the completed structure and review the submitted documents. The project owner shall notify the CPM after obtaining the CBO's final approval. The project owner shall retain one set of approved engineering plans, specifications and calculations (including all approved changes) at the project site or at another accessible location during the operating life of the project [2001 CBC, Section 106.4.2, Retention of Plans].

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 final approved engineering plans, specifications and calculations as described above, the project owner shall submit to the CPM a letter stating that the above documents have been stored and indicate the storage location of such documents.

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 Report, Geotechnical Report or Foundation Investigations Report required by the 2001 CBC [Appendix Chapter 33, Section 3309.5, Soils Engineering Report; Section 3309.6, Engineering Geology Report; and Chapter 18, Section 1804, Foundation Investigations].

Verification: At least 15 days (or project owner and CBO approved alternative timeframe) 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 [2001 CBC, Section 104.2.4, Stop 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 2001 CBC, Chapter 1, Section 108, Inspections; Chapter 17, Section 1701.6, Continuous and Periodic

Special Inspection; and Appendix Chapter 33, Section 3317, Grading Inspection. 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 [2001 CBC, Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. 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 [2001 CBC, Section 3318, Completion of Work].

Verification: Within 30 days (or project owner and CBO approved alternative timeframe) 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, 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 (or project owner and CBO approved alternative timeframe) listed in **Table 1** of Condition of Certification **GEN-2**, 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 1**, above):

1. Major project structures;
2. Major foundations, equipment supports and anchorage;
3. Large field fabricated tanks;
4. Turbine/generator pedestal; and
5. Switchyard structures.

Construction of any structure or component shall not commence 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 (i.e., 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 [2001 CBC, Section 108.4, 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 [2001 CBC, Section 106.4.2, Retention of plans; and Section 106.3.2, Submittal documents];
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 engineer [2001 CBC, Section 106.3.4, Architect or Engineer of Record]; and
5. Submit to the CBO the responsible engineer's signed statement that the final design plans conform to the applicable LORS [2001 CBC, Section 106.3.4, Architect or Engineer of Record].

Verification: At least 60 days (or project owner and CBO approved alternative timeframe) prior to the start of any increment of construction of any structure or component listed in Facility Design Table 1 of Condition of Certification **GEN-2**, 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 are in compliance with the requirements set forth in the applicable engineering LORS.

STRUC-2 The project owner shall submit to the CBO the required number of sets of the following documents related to work that has undergone CBO design review and approval:

1. Concrete cylinder strength test reports (including date of testing, date sample taken, design concrete strength, tested cylinder strength, age of test, type and size of sample, location and quantity of concrete placement from which sample was taken, and mix design designation and parameters);

2. Concrete pour sign-off sheets;
3. Bolt torque inspection reports (including location of test, date, bolt size, and recorded torques);
4. Field weld inspection reports (including type of weld, location of weld, inspection of non-destructive testing (NDT) procedure and results, welder qualifications, certifications, qualified procedure description or number (ref: AWS); and
5. Reports covering other structural activities requiring special inspections shall be in accordance with the 2001 CBC, Chapter 17, Section 1701, Special Inspections; Section 1701.5, Type of Work (requiring special inspection); Section 1702, Structural Observation and Section 1703, Nondestructive Testing.

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 [2001 CBC, Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector]. 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.

Verification: The project owner shall transmit a copy of the CBO's approval or disapproval of the corrective action to the CPM within 15 days. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action to obtain CBO's approval.

STRUC-3 The project owner shall submit to the CBO design changes to the final plans required by the 2001 CBC, Chapter 1, Section 106.3.2, Submittal documents and Section 106.3.3, Information on plans and specifications, including the revised drawings, specifications, calculations, and a complete description of, and supporting rationale for, the proposed changes, and shall give to the CBO prior notice of the intended filing.

Verification: On a schedule suitable to the CBO, the project owner shall notify the CBO of the intended filing of design changes, and shall submit the required number of sets of revised drawings and the required number of copies of the other above-mentioned documents to the CBO, with a copy of the transmittal letter to the CPM. The project owner shall notify the CPM, via the Monthly Compliance Report, when the CBO has approved the revised plans.

STRUC-4 Tanks and vessels containing quantities of toxic or hazardous materials exceeding amounts specified in Chapter 3, Table 3-E of the 2001 CBC shall, at a minimum, be designed to comply with the requirements of that Chapter.

Verification: At least 30 days (or project owner and CBO approved alternate timeframe) 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 1**, 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 said construction [2001 CBC, Section 106.3.2, Submittal Documents; Section 108.3, Inspection Requests; Section 108.4, Approval Required; 2001 California Plumbing Code, Section 103.5.4, Inspection Request; Section 301.1.1, Approval].

The responsible mechanical engineer shall stamp and sign all plans, drawings and calculations for the major piping and plumbing systems subject to the 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 [Section 106.3.4, Architect or Engineer of Record], which may include, but not be 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
Specific City/County code.
The CBO may deputize inspectors to carry out the functions of the code enforcement agency [2001 CBC, Section 104.2.2, Deputies].

<u>**Verification:**</u> At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of any increment of major piping or plumbing construction listed in Facility Design Table 1, 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 the 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 the applicable LORS. Upon completion of the installation of any pressure vessel, the project owner shall request the appropriate CBO and/or Cal-OSHA inspection [2001 CBC, Section 108.3, 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 engineer submit a statement to the CBO that the proposed final design plans, specifications and calculations conform to all of the requirements set forth in the appropriate ASME Boiler and Pressure Vessel Code or other applicable codes.

Verification: At least 30 days (or project owner and CBO approved alternative timeframe) 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. 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 to the applicable LORS [2001 CBC, Section 108.7, Other Inspections; Section 106.3.4, Architect or Engineer of Record].

Verification: At least 30 days (or project owner and CBO approved alternative timeframe) 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 electrical equipment and systems 480 volts and higher, listed 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 [CBC 2001, Section 106.3.2, 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 [2001 CBC, Section 108.4, Approval Required, and Section 108.3, Inspection Requests].

A. Final plant design plans to 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 to 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 energizing of major electrical equipment; and
   3. A signed statement by the registered electrical engineer certifying that the proposed final design plans and specifications conform to requirements set forth in the Energy Commission Decision.

<u>Verification:</u> At least 30 days (or project owner and CBO approved alternative timeframe) 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.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

FACILITY DESIGN

APPLICABLE LAW	DESCRIPTION
Title 24, California Code of Regulations, which adopts the current edition of the California Building Standards Code (CBSC); the 2001 CBSC for design of structures; American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code; and National Electrical Manufacturers Association (NEMA) standards.	The applicable LORS for each engineering discipline, civil, structural, mechanical and electrical, are included in the application as part of the engineering appendix, Appendix N.

RELIABILITY – Summary of Findings

Plant Availability	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** The Project Owner expects to operate at an overall availability in the mid-90 percent range.
Maintainability	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** The Project Owner will establish a plant maintenance program typical of the industry. Equipment manufacturers will provide maintenance recommendations with their products, and the Project Owner will base its maintenance program on these recommendations.
Fuel Availability	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** The project will burn natural gas supplied from the El Paso Natural Gas Company system. There is an adequate supply of natural gas to meet the project's needs. There is no back-up fuel supply.
Water Availability	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** Water for cooling will be drawn from two on-site groundwater wells. Potable water will be supplied by on-site water treatment.
Natural Disasters	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** Although located within seismic zone 3, the plant will perform as well or better than others in the electric power system by complying with the latest seismic design criteria of the California Building Standards Code. See **FACILITY DESIGN.**

RELIABILITY - GENERAL

Presently, there are no laws, ordinances, regulations or standards (LORS) that establish either power plant reliability criteria or procedures for attaining reliable operation. However, the Energy Commission must make findings as to the manner in which the project is to be designed, sited and operated to ensure safe and reliable operation (Cal. Code Regs., tit. 20, § 1752(c)). In past proceedings, the Commission has taken the approach that a project is acceptable if it does not degrade the reliability of the utility system to which it is to be connected. Thus, a project should exhibit reliability at least equal to that of other power plants on that system.

Plant Availability

The North American Electric Reliability Council (NERC) keeps industry statistics for availability factors. NERC continually polls utility companies throughout the North American continent on project reliability. In 2005, NERC reported an availability factor of 89.00 percent for combined cycle units of all sizes, for the years 1999 through 2003. The gas turbines that will be employed in the project have been on the market for several years, and can be expected to exhibit typically high availability. In fact, these new, large machines can be expected to outperform the fleet of various, mostly older and smaller, gas turbines that make up the NERC statistics. The project is expected to operate at an overall availability in the range of 92 to 98 percent and at a capacity factor, over the life of the plant, of 30-100 percent of base load (AFC §§ 2.4.1, 8.3.2).

Acceptable reliability can be accomplished by providing adequate redundancy of critical components. Equipment availability will be ensured by use of quality assurance/ quality control (QA/QC) programs during design, procurement, construction and operation of the plant, and by providing for adequate maintenance and repair of the equipment and systems.

The Applicant has provided an outline of the expectations for quality control from the design concept phase through project commissioning. Equipment will be purchased from qualified suppliers that employ an approved QC program. Designs will be checked and equipment inspected upon receipt; installation will be inspected and systems tested. To ensure such implementation, appropriate Conditions of Certification are included in **FACILITY DESIGN**. (FSA, p. 5.4-3)

Maintainability

As analyzed by Staff, a generating facility called on to operate in baseload service for long periods of time must be capable of being maintained while operating. A typical approach for achieving this is to provide redundancy of those pieces of equipment most likely to require service or repair. The Applicant plans to provide appropriate redundancy of function for the combined cycle portion of the project. The fact that the project consists of two trains of gas turbine generators/HRSGs provides inherent reliability. Failure of a non-redundant component of one train should not cause the other train to fail, thus allowing the plant to continue to generate, though at reduced output. Further, the plant's distributed control system (DCS) will be built with typical redundancy. Redundant batteries, chargers, and inverters will supply emergency DC and AC power systems. (AFC 1.2, 3.10, 5.19-4; Appendix F; FSA Reliability, pp. 5.4-3, 4.)

The Applicant proposes to establish a plant maintenance program based on good utility practices typical of the industry. Equipment manufacturers provide maintenance recommendations with their products; The Applicant will base its maintenance program on these recommendations. In light of these plans, the project will be adequately maintained to ensure acceptable reliability. (AFC §2.4.1; FSA, p. 5.4-4.)

Fuel Availability

The BEP II will burn natural gas from the El Paso Natural Gas Company (EPNGC) distribution system. Gas will be transmitted to the plant via a new pipeline connection to the approved BEP I gas supply system. This EPNGC natural gas system represents a reliable source of considerable capacity. This system offers access to adequate supplies of gas. Staff agrees with the Applicant's prediction that there will be adequate natural gas supply and pipeline capacity to meet the project's needs. (AFC §8.3.1; FSA, p. 5.4-4.)

Water Availability

The BEP II would obtain water from two additional wells constructed on-site that will supply cooling water for the steam turbine condenser. The Applicant predicts average water consumption of approximately 2,200 gallons per minute (gpm). Potable water will be provided by the water treatment system. (AFC §§ 2.2.8, 2.2.8.1, 2.2.8.5.2) Although Staff contests the project's use of groundwater, Staff acknowledges that groundwater would be a reliable supply of water. (FSA, p. 5.4-4)

Natural Disasters

Natural forces can threaten the reliable operation of a power plant. High winds, flooding, and tsunamis (tidal waves) will not likely represent a hazard for this project, but seismic shaking (earthquake) presents a credible threat to reliable operation.

The site lies within Seismic Zone 3. The project will be designed and constructed to the latest appropriate seismic design criteria of the California version of the Uniform Building Code. By being constructed and built to the latest, upgraded seismic design criteria, this project will likely perform at least as well as, and perhaps better than, existing plants in the electric power system. (FSA, p. 5.4-5) This Decision contains Conditions of Certification to ensure the project is constructed in conformity with the latest California Building Standards Code. See **FACILITY DESIGN**.

Finding

Without Conditions of Certification, the project conforms to applicable laws related to reliability.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

RELIABILITY

APPLICABLE LAW	DESCRIPTION
None	

TRANSMISSION LINE SAFETY & NUISANCE – Summary of Findings and Conditions

Electric & Magnetic Fields	**COMPLIES WITH APPLICABLE LAW & REGULATIONS** BEP II would connect to the existing Western Area Power Administration (Western) Buck Boulevard Substation located at the northeastern corner of the BEP I site. The BEP II transmission line would be entirely within the fenced BEP I and BEP II sites. **CONDITION:** ☑ The Project Owner shall design and construct lines in compliance with CPUC's GO-95, GO-52, Title 8, Sections 2700 through 2974 of the California Code of Regulations and Western's EMF-reduction guidelines. Condition: **TSLN-1**.
Aviation Safety	**COMPLIES WITH APPLICABLE LAW & REGULATIONS** The Blythe Airport is located approximately one mile from the project site. The proposed BEP II transmission line would be designed and sited in compliance with FAA regulations regarding collision related aviation safety, by being less than the 200-foot FAA height threshold for a potentially significant collision hazard.
Radio & TV Interference	**COMPLIES WITH APPLICABLE LAW & REGULATIONS** Federal and State regulations regulate transmission line-related radio and TV-frequency interference. Conditions are set forth herein to ensure that any interference is mitigated whenever interference occurs. **CONDITION:** ☑ The Project Owner shall investigate and, as feasible, remedy any project-related television or radio interference. Condition: **TSLN-2**.
Audible Noise	**COMPLIES WITH APPLICABLE LAW & REGULATIONS** There are no design specific federal regulations to limit audible noise from transmission lines. As with radio noise, such noise is limited instead through design and maintenance standards established from industry research and experience.

Fire Hazard	**COMPLIES WITH APPLICABLE LAW & REGULATIONS**
	State regulations set forth guidelines to minimize potential fire hazards from overhead lines. **CONDITION:** ☑ The Project Owner shall keep the transmission line right-of-way free of combustible materials. Condition: **TSLN-4**.
Shocks	**COMPLIES WITH APPLICABLE LAW & REGULATIONS**
	State regulations and industrial standards set forth guidelines to prevent hazardous shocks from power lines. Grounding prevents nuisance shocks. **CONDITION:** ☑ The Project Owner shall ground metallic objects within the right-of-way. Condition: **TSLN-5**.

TRANSMISSION LINE SAFETY & NUISANCE – GENERAL

The Warren-Alquist Act requires the Commission to "prepare a written decision … which includes:

> (a) Specific provisions relating to the manner in which the proposed facility is to be designed, sited, and operated in order to protect environmental quality and assure public health and safety, [and]
>
> (d)(1) Findings regarding the conformity of the proposed site and related facilities…with public safety standards…and with other relevant local, regional, state and federal standards, ordinances, or laws…" (Pub. Resources Code, §25523).

BEP II would be electrically connected to the existing Western Area Power Administration (Western) Buck Boulevard Substation located at the northeastern corner of the BEP I site, previously permitted by the California Energy Commission. BEP I is presently connected to this same Buck Boulevard Substation through three short tie lines.

Western proposes to construct a new 118-mile, single-circuit 500 kV Desert Southwest Transmission Project (DSWTP) interconnection to the SCE Devers Substation, which would also deliver the BEP II-generated power to the region's load centers via the California Independent System Operator (CAL ISO) power grid. This new 118-mile transmission line is not part of BEP II project and is being separately reviewed and permitted by federal agencies.

The potential impacts of most concern in this analysis are those from transmitting the BEP II generated energy to the Buck Boulevard Substation. The DSWTP is noted because of its evaluation from a cumulative impacts perspective.

The proposed BEP II connection to the Buck Boulevard Substation is an overhead, 2,500-ft, 500 kV line stretching from BEP II's generators to the connection points within the Substation. It would be located entirely within the BEP I/BEP II site boundaries, meaning that no off-site power lines would be constructed with specific regard to the proposed BEP II. (FSA, p. 4.11-1)

Electric & Magnetic Fields

The possibility of health effects from exposure to electric and magnetic fields has increased public concern in recent years about living near high-voltage lines. Both fields occur together whenever electricity flows, hence the general practice of considering exposure to both as EMF exposure. The available evidence, as evaluated by California Public Utilities Commission (CPUC) and other regulatory agencies, has not established that such fields pose a significant health hazard to exposed humans.

However, the Energy Commission 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. Therefore, in light of present uncertainty, it is appropriate to reduce such fields where feasible, until the issue is better understood. (FSA, p. 4.11-5, 6 & 9-11)

Since each new line in California is currently required to be designed according to the safety and EMF-reducing guidelines of the utility in the service area involved, their fields are required under existing CPUC policies to be similar to fields from similar lines in that service area. Condition **TLSN-1** requires the Applicant to comply with Western's practices to comply with the CPUC's policy on field strength management.

CONDITION:

- ☑ The Project Owner shall design and construct lines in compliance with CPUC's GO-95, GO-52, Title 8, Sections 2700 through 2974 of the California Code of Regulations and Western's EMF-reduction guidelines. Condition: **TSLN-1**.

Aviation Safety

The Blythe Airport is located approximately one mile from the project site, raising to the potential of a collision hazard to aircraft. As with area Western lines, the proposed BEP II line would be designed and sited in compliance with FAA regulations regarding collision related aviation safety. Furthermore, the proposed BEP II site is 60 feet to 70 feet lower in elevation than the Blythe Airport. When this is considered together with the fact that the proposed line would be less than the 200-foot FAA height threshold for a potentially significant collision hazard, the proposed BEP II to Buck Boulevard Substation line is unlikely to constitute a new collision hazard to area aircraft. As is common industry practice, however, the Applicant will inform the FAA about the proposed line, although no FAA notification would otherwise be required. The GO-95 clearance requirements would produce the 37-ft minimum height adequate for safe crop-dusting related operations. (FSA, p. 4.11-8)

Radio & TV Interference

Transmission line-related radio-frequency interference is one of the indirect effects of line operation produced by the physical interactions of line electric fields. The level of such interference usually depends on the magnitude of the electric fields involved. Because of this, the potential for such impacts can be assessed from field strength estimates obtained for the line. Applicable regulations are intended to ensure that such lines are located away from areas of potential interference and that any interference is mitigated whenever it occurs.

Since there are no residences around any of the project-related lines, BEP II operations are not expected to generate any complaints about interference with the use of residential radio, television, or other electrical equipment. In the unlikely event of specific complaints, the transmission line owner would be responsible for the necessary mitigation as required by the FCC. See Condition **TLSN-2**. (FSA, p. 4.11-2-3 & 9)

CONDITION:

- ☑ The Project Owner shall investigate and, as feasible, remedy any project-related television or radio interference. Condition: **TSLN-2**.

Audible Noise

There are no design-specific federal regulations to limit the audible noise from transmission lines. As with radio noise, such noise is limited instead through design and maintenance standards established from industry research and experience. These standards have proven effective without significant impacts on line safety, efficiency, maintainability, and reliability. Any noise will usually result from the action of the electric field at the surface of the line conductor and could be perceived as a characteristic crackling, frying, hissing sound, or hum. Since (as with communications interference), the noise level depends on the strength of the line electric field, the potential for occurrence can be assessed from estimates of the field strengths expected during operation. Such noise is generated during wet weather and from lines of 345 kV or higher. (FSA, p. 4.11-4)

All existing Western lines were built and are currently maintained according to standard Western practices that minimize surface irregularities and discontinuities that cause corona-related noise. The low-corona design to be used for the new on-site line would be the same as used for other Western lines of the same voltage in compliance with FCC (47 CFR §15.25) and CPUC (GO-52) prohibitions against interference with radio communication. Since there are no residences around any of the project-related lines, BEP II operations are not expected to generate any complaints about operational noise. (FSA, p. 4.11-9)

Fire Hazard

Standard fire prevention and suppression measures for all of Western's lines would be implemented for the proposed BEP II on-site 500 kV line and would be maintained as is standard Western practice. The Applicant's intention to ensure compliance with the clearance-related aspects of GO-95 would be an important part of this compliance approach. Western's fire prevention practices for high-voltage lines would be implemented in compliance with Title 14, California Code of Regulations, section 1250. Condition **TLSN-4**.

CONDITION:

- ☑ The Project Owner shall keep the transmission line right-of-way free of combustible materials. Condition: **TSLN-4**.

<u>Shocks</u>

There are no design-specific federal regulations to limit nuisance shocks in the transmission line environment. For modern high-voltage lines, such shocks are effectively minimized through grounding procedures specific in the National Electrical Safety Code and the joint guidelines of the American National Standards Institute and the joint guidelines of the Institute of Electrical and Electronics Engineers.

Since the proposed on-site 500 kV line would be designed according to GO-95 requirements together with the requirements in specific sections of Title 8, California Code of Regulations, section 2700 et seq. against direct contact with the energized line, the new transmission line does not pose a significant shock hazard.

Nuisance shocks are caused by current flow at levels generally incapable of 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 electric and magnetic fields. The potential for nuisance shocks around the new on-site project line would be minimized through standard grounding practices, as are the permitted BEP I and similar Western lines. Condition **TLSN-5**.

CONDITION:

- ☑ The Project Owner shall ground metallic objects within the right-of-way. Condition: **TSLN-5**.

<u>Cumulative Impacts</u>

Magnetic fields were calculated to reflect the interactive effects of the fields from all the grid lines in the corridor of maximum BEP II impacts and should therefore be seen as representing the maximum post-BEP II exposures of a cumulative nature. As reflected in the calculated values, the lines' potential contribution to any area exposures would be similar to those associated with area Western lines of the same voltage and current-carrying capacity. It is this similarity in field intensity (which reflects the effective implementation of the applicable field strength-minimizing measures) that constitutes compliance with existing CPUC requirements on line field management. The field strength measurement requirements in Condition of Certification **TLSN-3** would allow for assessment of the field strength reduction efficiency presented by the Applicant. The power diversion through the proposed 118-mile line to the Devers Substation would decrease cumulative magnetic field exposure by the amounts reflected in the pre- and post-BEP II field strengths.

If the Desert Southwest Transmission Project, Blythe Energy Project Transmission Lines, and the proposed Devers to Palo Verde II lines were actually built to facilitate the noted regional power transmission, they would be mostly located within a right-of-way adjacent to the right-of-way for SCE's existing Devers to Palo Verde I line. The combined impacts of these area lines could manifest themselves as the field and non-field impacts assessed in this analysis. Given that the required line designs would be adequate to minimize such impacts and that these rights-of-way would traverse an area with no nearby residents or airports, any cumulative impacts of these projects are not expected to be environmentally significant. (FSA, p. 4.11-11)

Finding

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to transmission line safety.

CONDITIONS OF CERTIFICATION

TLSN-1 The project owner shall ensure that the proposed on-site 500 kV project line is designed and constructed as specified for lines of this voltage class in CPUC's GO-95, GO-52, the applicable sections of Title 8, California Code of Regulations section 2700 et seq., and Western's EMF reduction guidelines arising from CPUC Decision 93-11-013.

Verification: Thirty days before starting construction of the BEP II transmission line or related structures and facilities, the project owner shall submit to the Compliance Project Manager (CPM) a letter signed by a California registered electrical engineer affirming compliance with this requirement.

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 project-related lines and associated switchyards.

The project owner shall maintain written records, for a period of five years, of all complaints of radio or television interference attributable to operation of the plant and the corrective action taken in response to each complaint. Complaints not leading to a specific action or for which there was no resolution should be noted and explained. The record shall be signed by the project owner and also the complainant, if possible, to indicate concurrence with the corrective action or agreement, with the justification for a lack of action.

Verification: All reports of line-related complaints shall be summarized for the project-related lines and included for the first five years' of plant operation in the Annual Compliance Report.

TLSN-3 The project owner shall engage a qualified consultant to measure the strengths of the electric and magnetic fields from the proposed on-site 500 kV line and any BEP I-related lines to be utilized. Measurements shall be made at the Western Buck Boulevard Substation, Western Blythe Substation, and the maximum impact points within and along and at the edges of the right-of-way (for which the Applicant presented field strength estimates). All measurements should be made according to Institute of Electrical and Electronics Engineers (IEEE) measurement protocols.

Verification: The project owner shall file copies of the pre-and post-energization measurements with the CPM within 30 days after completion of the measurements. While pre-energization measurements can be made anytime before energization; post-energization measurements shall be initiated within 60 days of after operations commence.

TLSN-4 The project owner shall ensure that the route of the project's on-site 500 kV line is kept free of combustible material according to existing Western practices reflecting compliance with the provisions of Section 4292 of the Public Resources Code and Section 1250, Title 14, of the California Code of Regulations.

Verification: At least 30 days before the line is energized, the project owner shall transmit to the CPM a letter confirming compliance with this condition.

TLSN-5 The project owner shall ensure that all permanent metallic objects within the right-of-way of the proposed 500 kV on-site lines are grounded according to industry standards.

Verification: At least 30 days before the line is energized, the project owner shall transmit to the CPM a letter confirming the intention to comply with this condition. A confirmatory letter of compliance shall be transmitted to the CPM within 30 days of completing the grounding operations.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

TRANSMISSION LINE SAFETY AND NUISANCE

APPLICABLE LAW	DESCRIPTION
FEDERAL	
14 CFR Part 77 – Objects Affecting the Navigation Space	Provides regulates that specify the criteria used by the FAA for determining whether a Notice of Proposed Construction or Alteration is required for potential obstruction hazards.
Title 47 CFR §15.25	Prohibits operation of any devices producing force fields that interfere with radio communications, even if such devices are not intentionally designed to produce radio-frequency energy.
STATE	
CPUC General Order 52	Governs the construction and operation of power and communications lines
CPUC General Order 128	Specifies criteria for underground transmission lines.
Title 14 CCR §1250	Specifies utility-related measures for fire protection.
Title 8 CCR, §2700 et seq.	Establishes requirements and standards for safely installing, operating and maintaining electrical installations and equipment.
LOCAL	
There are no applicable Local LORS for this area.	

TRANSMISSION SYSTEM ENGINEERING – Summary of Findings and Conditions

Grid Planning/ Reliability	COMPLIES WITH APPLICABLE LAWS & REGULATIONS
	BEP II proposes to connect to Western's Buck Boulevard Substation adjacent to BEP I. In order to handle all of BEP II's generation, the Imperial Irrigation District will need to complete permitting review of the Desert Southwest Transmission Project (DSWTP), which will connect to SCE's Devers Substation. Western's System Impact Study concluded that BEP II and the DSWTP present no negative impact to Western's system, provided Remedial Action Schemes are implemented to prevent no more than 520 MW from BEP I and BEP II to flow to the existing 161 kV system in the event the DSWTP line suffers an outage. Western will be proceeding with the required System Facilities Study to determine the specific interconnection requirements and costs for BEP II's interconnection at the Buck Boulevard Substation. The Applicant will not begin construction of the project until the DSWTP (or an equivalent) has obtained all necessary permits. In addition, the BEP I and BEP II projects would not deliver more than 520 MW until the DSWTP (or an equivalent) is in operation.

TRANSMISSION SYSTEM ENGINEERING – GENERAL

The Warren-Alquist Act requires the Commission to "prepare a written decision ….which includes:

> (a) Specific provisions relating to the manner in which the proposed facility is to be designed, sited, and operated in order to protect environmental quality and assure public health and safety, [and]
>
> (d)(1) Findings regarding the conformity of the proposed site and related facilities…with public safety standards…and with other relevant local, regional, state and federal standards, ordinances, or laws…" (Pub. Resources Code § 25523).

Under California's 1996 Electricity Industry Deregulation legislation, Southern California Edison (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas and Electric Company (SDG&E) divested most of their power plants but retained ownership of their electric transmission and distribution systems, under the operating control of the California Independent System Operator (Cal-ISO). Cal-ISO is responsible for ensuring electric system reliability for all participating transmission owning utilities and determines both the standards necessary to achieve reliability and whether a proposed project conforms to those standards.

The Energy Commission relies on the Cal-ISO's determinations to make its finding related to applicable reliability standards and the need for additional transmission facilities. The Energy Commission conducts an environmental review of the proposed project. The Energy Commission must also consider any additional transmission facilities recommended by Cal-ISO as part of the "whole of the action" even though the additional facilities are not licensed by the Energy Commission (CCR, tit. 14, §15378).

The Applicant proposes to construct a 500kV switchyard on the BEP II site and then connect to the existing Buck Boulevard Substation, identified as part of the BEP I site licensing, but wholly owned and constructed by Western Area Power Administration (Western). The interconnection between the BEP II project and the Substation will be with a single circuit 500kV transmission line, approximately 2,300 feet long. The transmission line with double-bundled conductors will be supported on six 125-foot poles.

Uniquely for this project, Western does not currently have the capacity to transmit all of BEP II's generation output into the interconnected transmission grid. The Imperial Irrigation District (IID) is overseeing the Desert Southwest Transmission Line Project (DSWTP), a proposed new 118-mile transmission line from Buck Boulevard Substation (on the BEP I site) to the Southern California Edison Company's Devers Substation, approximately 10 miles north of Palm Springs, which would be capable of transmitting more than the project generation. As such, the DSWTP is a separate project, which would be constructed notwithstanding BEP II.

Grid Planning

The Applicant cites the 2002-2003 Blythe Area Regional Transmission (BART) Study, which concluded that the Desert Southwest Transmission Project (DSWTP) 500 kV line would be the preferred transmission option to transmit the output of BEP II from Western's Buck Boulevard Substation to the California Independent System Operator (Cal ISO) grid.

The BART Study was conducted in response to Staff's need for input from the regional transmission owners and operator to develop a common base case that would allow the assessment of the regional impacts to the transmission system under various transmission options for the BEP II project. The participants included Western, the Imperial Irrigation District, Southern California Edison, the Metropolitan Water District, and the Energy Commission staff. The 20-month study process was not intended to fulfill each transmission owner's tariff requirements for a system impact study. However, the Study included power flow, transient stability, short circuit, and post-transient analysis to assess the impact of BEP II interconnecting at the Western Buck Boulevard 500 kV Substation and the DSWTP connected from there to SCE's Devers 500 kV substation.

Overall, the BART Study concluded that the BEP II interconnection to the Buck Bulevard Substation with the 500 kV DSWTP from Buck to Devers would have little, but mitigable, impact on the interconnected system.

In May 2005, Western completed a System Impact Study (SIS) for the BEP II interconnection to the Buck Boulevard Substation. The SIS concluded that BEP II and the DSWTP presents no negative impact to Western's system, provided Remedial Action Schemes are implemented to prevent no more than 520 MW from BEP I and BEP II to flow to the existing 161 kV system in the event the DSWTP line suffers an outage. Western will be proceeding with the required System Facilities Study to determine the specific interconnection requirements and costs for interconnecting the project at the Buck Boulevard Substation.

The Applicant has offered a Condition of Certification that it will not begin construction of the project until the DSWTP (or an equivalent) has obtained all necessary permits. In addition, the BEP I and BEP II projects would not deliver more than 520 MW until the DSWTP (or an equivalent) is in operation. (Looper, pp. 2-8)

Energy Commission staff believes that it cannot determine conformance to applicable laws from both an *engineering* and *reliability* perspective with available information. Nor can Staff identify the "whole of the action" per the California Environmental Quality Act (CEQA) because the project interconnection facilities and the transmission option are unidentified, uncertain and infeasible at this stage. Staff recommends against certification of the project until it receives and analyzes a System Impact Study with BEP II in the third position in the queue of other regional transmission projects and proposed interconnections.

Commission Discussion

The Commission finds that the DSWTP is a separate project from the BEP II. The SWDTP is in a permitting process with appropriate Environmental Impact Reports and Statements from the Bureau of Land Management and Imperial Irrigation District. The environmental documentation assesses four alternative routes, mostly along existing transmission corridors, and concludes that all potential adverse impacts can be mitigated. (Looper, p. 9) Since the DSWTP is a separate project, discussing the DSWTP process and its environmental findings to date fulfills our obligations under CEQA in this proceeding.

In order for the DSWTP to be interconnected with the grid, it must comply with all applicable requirements for reliability and safety. Inherently, the DSWTP cannot be available for interconnecting at the Buck Boulevard Substation if it does not comply with such requirements. Therefore, no Energy Commission conditions attach to the DSWTP nor prevent BEP II from interconnecting to the DSWTP at the Buck Boulevard Substation. We have included appropriate conditions on the transmission tie line from the project switchyard to the Buck Boulevard Substation.

Buck Boulevard Substation

The Western owned and operated Buck Boulevard Substation will require new equipment in order to receive the 500kV generation from the BEP II project. The Applicant and Staff dispute Staff-proposed conditions that would require Energy Commission CPM approval of Western's modifications and additions to the Substation in order to ensure grid reliability.

Prior Commission decisions give guidance on this issue. In the BEP I Decision (99-AFC-8), stated in pertinent part:

> Western is responsible for ensuring electric system reliability for Western's transmission system and determines both the standards necessary to achieve reliability and whether a proposed project conforms to those standards. The California Integrated System Operator (Cal-ISO) is responsible for insuring reliability for the portion of the adjoining California transmission system owned by Cal-ISO participating transmission owners. The Cal-ISO is not the interconnection authority for Western's system, but may provide technical consultation to [CEC] staff on Western's determinations and findings related to applicable reliability standards and the need for additional transmission facilities.
>
> …
>
> Western design standards will be used. The final designed project tie lines will be sized to accommodate continuous full plant output, and line construction will meet or exceed Western's, [CPUC] GO-95 and National Electric Safety Code (NESC) specifications, in accordance with conditions of certification **TSE-1a** and **TSE-1d**.
>
> …
>
> Western is the transmission owning agency that will provide transmission service to the project as well as being the agency responsible for maintaining reliability of Western's interconnected grid. As such, Western will perform the analysis identifying impacts, recommend the interconnection facilities and any mitigation of downstream facilities required to maintain system reliability, and Western will ultimately approve the final interconnection requirements for the project.
>
> …
>
> Completion of pending WSCC per review, completion of a final Facilities Study by Western, and any future issuance of an interconnection agreement from Western, will assure conformance with NERC, WSCC and Western reliability criteria. Condition of Certification TSE-1e is adopted to provide for Commission review of the WSCC Peer Review report, Western's Final Facility Study, and the Western/BEP interconnection agreement. (BEP I Decision, pp. 79 – 81)

The Commission also approved the interconnection of the East Altamont project (01-AFC-4) to a Western substation, requiring similar provisions found in Condition of Certification **TSE-1(8)**.

Western's interest in this matter is that it agrees to cooperate with the implementation of Energy Commission conditions, which means providing copies of its Detailed Facility Study, downstream mitigations, if any, and a final Interconnection Agreement, so long as language makes it clear that Western is not "ceding any authority over Federal facilities to the State of California." (Staff Opening Brief, p. 27)

Condition of Certification **TSE-5(f)**, below, incorporates provisions similar to those found in the BEP I and East Altamont Decisions, without asserting jurisdiction over federal facilities. The information provided by Western, through the project owner, will confirm that Western's actions related to its Buck Boulevard Substation maintain system reliability.

Cumulative Impacts

While cumulative transmission impacts caused by the combined operation of the project and other proposed projects are possible, these potential impacts are highly speculative because of the uncertainty surrounding projects proposed by other generators. Mitigation of such impacts will be the responsibility of other project developers, and any impacts caused by the BEP II project will be mitigated as previously identified.

Finding

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to transmission system engineering.

CONDITIONS OF CERTIFICATION

TSE-1 The project owner shall furnish to the CPM and to the CBO a schedule of transmission facility design submittals, a Master Drawing List, a Master Specifications List, and a Major Equipment and Structure List for the BEP II transmission facilities to the first point of interconnection at the Buck Blvd Substation. 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. This condition applies only to the power plant Integration Switchyard and transmission tie line.

Verification; At least 60 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of construction of any transmission facility, the project owner shall submit the schedule, an updated Master Drawing List, and a Master Specifications List to the CBO and to the CPM. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see a list of major equipment in Table 1: Major Equipment List (below). Additions and deletions shall be made to the table only with CPM and CBO approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

Table 1: Major Equipment List
Breakers
Step-up Transformer
Switchyard
Busses
Surge Arrestors
Disconnects
Take off facilities
Electrical Control Building
Switchyard Control Building
Transmission Pole/Tower
Grounding System

TSE-2 Prior to the start of construction of the power plant Integration Switchyard or transmission tie line to the Buck Boulevard Substation, 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 to 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.

<u>Verification:</u> At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading for transmission related facilities to the first point of interconnection at Buck Boulevard, 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 transmission facility engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend corrective action. (1998 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall become a controlled document and shall be submitted to the CBO for review and approval and shall reference this condition of certification.

__Verification:__ The project owner shall submit a copy of the CBO's approval 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 to obtain the CBO's approval.

TSE-4 For the power plant Integration Switchyard, outlet line and termination, the project owner shall not begin any increment of construction until plans for that increment have been approved by the CBO. These plans, together with design changes and design change notices, shall remain on the site for one year after completion of construction. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS. The following activities shall be reported in the Monthly Compliance Report:

a) receipt or delay of major electrical equipment;
b) testing or energizing of major electrical equipment; and
c) the number of electrical drawings approved, submitted for approval, and still to be submitted.

__Verification:__ At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of each increment of construction, the project owner shall submit to the CBO for review and approval the final design plans, specifications and calculations for equipment and systems of the power plant switchyard, outlet line and termination, including a copy of the signed and stamped statement from the responsible electrical engineer attesting to compliance with the applicable LORS, and send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.

TSE-5 The project owner shall ensure that the design, construction and operation of the proposed power plant Integration Switchyard and transmission tie line facilities to the Buck Boulevard Substation will conform to all applicable LORS, including the requirements and description listed below. No increment of construction of these facilities shall commence until the CPM approves the documents required in the Verification for **TSE-5**. The project owner shall submit the required number of copies of the design drawings and calculations as determined by the CBO.

The BEP II 500 kV integration switchyard shall have four switchbays with 500 kV circuit breakers. The high voltage transformer terminals of two CTGs and one STG unit shall be connected by overhead conductors to three switch bays. The fourth bay shall be connected to a 500 kV 2-2156 Aluminum Conductor Steel Reinforced (ACSR) interconnecting line to a new 500 kV substation to be built within the existing Buck Boulevard Substation.

The Integration Switchyard shall be connected to the Buck Blvd. 500 kV Bus via a 500 kV single circuit transmission line.

a) The power plant Integration Switchyard and outlet line shall meet or exceed the electrical, mechanical, civil and structural requirements of CPUC General Order 95 or National Electric Safety Code (NESC), Title 8 of the California Code and Regulations (Title 8), Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", Western Interconnection standards, IEEE grounding standards, National Electric Code (NEC) and related industry standards.
b) Breakers and busses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis.
c) 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.
d) The project conductors shall be sized to accommodate the full output from the project.
e) Termination facilities shall comply with applicable Western interconnection standards.
f) The project owner shall provide to the CPM:

   i) A System Impact Study and a final Detailed Facility Study (DFS) conducted by Western which includes, with respect to the major equipment listed in Table 1 of TSE-1, the following:
      (1) a description of all interconnection facilities with a one-line diagram including BEP II integration switchyard and the new Buck Boulevard 500 kV substation showing major equipment and their ratings.
      (2) a description of any mitigation measures selected by project owner (to offset reliability criteria violations) and letters or reports of acceptance from the affected transmission owners and where applicable, the CA ISO.

   ii) Executed Facility Interconnection Agreement between the BEP II project owner and Western.

Verification: At least 90 days prior to the start of construction of transmission facilities to the first point of interconnection at the Buck Blvd. Substation (or a lesser number of days mutually agreed to by the project owner and CBO), the project owner shall submit to the CBO and where applicable the CPM for approval:

a) Design drawings, specifications and calculations conforming with CPUC General Order 95 or NESC, Title 8, Articles 35, 36 and 37 of the "High Voltage Electric

Safety Orders”, NEC, applicable interconnection standards and related industry standards, for the poles/towers, foundations, anchor bolts, conductors, grounding systems and major switchyard equipment listed in Table 1 of Condition TSE-1.

b) For each element of the transmission facilities identified above, the submittal package to the CBO shall contain the design criteria, a discussion of the calculation method(s), a sample calculation based on “worst case conditions” 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”, IEEE grounding standards, NEC, applicable interconnection standards, and related industry standards.

c) Electrical one-line diagrams signed and sealed by the registered professional electrical engineer in responsible charge, a route map, and an engineering description of equipment and the configurations covered by requirements **TSE-5** a) through f) above.

d) Item f) above submitted to the CPM for review and docketing.

TSE-6 The project owner shall inform the CPM and CBO of any impending changes, which may not conform to the requirements **TSE-5** a) through e), and have not received CPM and CBO approval, and request approval to implement such changes. A detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change shall accompany the request. Construction involving changed equipment shall not begin without prior written approval of the changes by the CBO and the CPM.

Verification: At least 60 days prior to the construction of transmission facilities to the first point of interconnection at the Buck Blvd. Substation, the project owner shall inform the CBO and the CPM of any impending changes which may not conform to requirements of **TSE-5** and request approval to implement such changes.

TSE-7 The project owner shall provide the following notices to the Western Area Power Administration, Desert Southwest Region (Western, DSR) and the California Independent System Operator (Cal-ISO) prior to synchronizing the facility with the Western transmission system:

1. At least one week prior to synchronizing the facility with the grid for testing, provide the Western, DSR and Cal-ISO a letter stating the proposed date of synchronization; and
2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the Western, DSR and Cal-ISO Outage Coordination Department.

Verification: The project owner shall provide copies of the Western, DSR and Cal-ISO letters to the CPM when they are sent to the Western, DSR and Cal-ISO one week prior to initial synchronization with the grid. The project owner shall contact the Western, DSR and Cal-

ISO Outage Coordination Department, Monday through Friday, between the hours of 0700 and 1530 at (916) 351-2300 at least one business day prior to synchronizing the facility with the grid for testing. A report of conversation with the Western, DSR and Cal-ISO shall be provided electronically to the CPM one day before synchronizing the facility with the Western, DSR California transmission system for the first time.

TSE-8 The project owner shall be responsible for the inspection of the power plant Integration Switchyard and transmission tie line to the Buck Blvd. Substation during and after project construction, and any subsequent CPM and CBO approved changes thereto, to ensure conformance with CPUC GO-95 or NESC, Title 8, CCR, Articles 35, 36 and 37 of the, "High Voltage Electric Safety Orders", applicable interconnection standards, IEEE grounding 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 action(s) 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 Integration Switchyard and the 500 kV line to the Buck Blvd. Substation 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 IEEE grounding standards, and applicable interconnection standards, NEC, 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.

TSE-9 The Project Owner shall not commence construction of BEP II until the Desert Southwest Transmission Project (DSWTP) or an equivalent transmission Project or Upgrade as determined by the CPM has received all necessary permits to build the Project or Upgrade and has a definite construction schedule.

Verification: At least 60 days prior to the start of rough grading or construction, the Project Owner shall submit the following to the CPM:

1. A list of all permits, agreements and approvals required for the construction, operation and interconnection of the DSWTP or the approved equivalent Project or Upgrade.
2. The permits, agreements and approvals required for the construction, operation and interconnection of the DSWTP or the approved equivalent Project or Upgrade when they become available.
3. A definite schedule for the construction and completion of the DSWTP or approved equivalent Project or Upgrade.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

TRANSMISSION SYSTEM ENGINEERING

APPLICABLE LAW	DESCRIPTION
FEDERAL	
There are no applicable Federal LORS	
STATE	
CPUC General Order 95, Rules for Overhead Electric Line Construction.	Formulates uniform requirements for construction of overhead lines
CPUC Rule 21	Provides standards for the reliable connection of parallel generating stations connected to participating transmission owners.
Western Systems Coordinating Council (WSCC)	Provides the performance standards used in assessing reliability of the interconnected system.
North American Electric Reliability Council (NERC)	Provides policies, standards, principles and guides to assure the adequacy and security of the electric transmission system.
LOCAL	
There are no applicable Local LORS for this area.	

WORKER SAFETY – Summary of Findings and Conditions

Fire Protection	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** The proposed fire protection system at the site will include fire alarms, detection systems, fire hydrants, water storage, and both primary electric and backup diesel water pumps and hose stations throughout the facility. The system will be designed and operated in accordance with National Fire Protection Association (NFPA) standards and recommendations. Prior to construction and operation of the project, the City of Blythe Fire Department shall confirm the adequacy of the proposed fire protection systems and plans. **CONDITION:** ☑ The Project Owner shall submit fire protection plans for the construction and operation of the project. Conditions: **WORKER SAFETY-1**, **WORKER SAFETY-2.**
Safety & Injury Prevention	**COMPLIES WITH APPLICABLE LAWS & REGULATIONS** Construction: During the construction phase of the project, workers will be exposed to hazards typical of construction of a gas-fired combined cycle facility. Construction Safety Orders are promulgated by Cal/OSHA and are applicable to the construction phase of the project. **CONDITION:** ☑ The Project Owner shall prepare a Construction Safety and Health Program for the review and comment by the City of Blythe Fire Department and Riverside County Fire Department. Condition: **WORKER SAFETY-1**. Operation: Prior to operation, the Project Owner shall prepare the Operations Safety and Health Program, which will include an Injury and Illness Prevention Program, an Emergency Action Program/Plan, a Fire Protection and Prevention Program; and a Personal Protective Equipment Program. **CONDITION**: ☑ The Project Owner shall prepare an Operations and Maintenance Safety and Health Program for the review and approval of Cal/OSHA and, as appropriate, review and comment of the City of Blythe Fire Department and Riverside County Fire Department. Condition: **WORKER SAFETY-2**.

Noise	COMPLIES WITH APPLICABLE LAWS & REGULATIONS
	Cal-OSHA regulations provide the maximum noise level over an 8-hour work period is 90 dBA. Areas above 85 dBA need to be posted as high noise level areas and appropriate hearing protection will be provided. The Project Owner will also adopt a hearing conservation program in accordance with Cal-OSHA regulations. **CONDITION:** ☑ The Project Owner shall institute an occupational noise control program to reduce exposure to high levels of construction noise. Condition: **NOISE-3.** ☑ The Project Owner shall conduct an occupational noise survey to identify noise hazardous areas and, if necessary, prepare mitigation in consultation with Cal/OSHA to reduce noise to prescribed limits. Condition: **NOISE-7**.

WORKER SAFETY - GENERAL

The requirements for worker safety and fire protection are enforced through Federal, State, and local regulations. The State of California Department of Industrial Relations is charged with the responsibility for administering the Cal/OSHA plan. Effective implementation of worker safety programs at a facility is essential to the protection of workers from workplace hazards. These programs are documented through project-specific worker safety plans. Industrial workers at the proposed facility will operate equipment, handle hazardous materials, and face other workplace hazards that may result in accidents or serious injury. The worker safety and fire protection measures proposed for this project are designed to either eliminate or minimize such hazards through special training, use of protective equipment or implementation of procedural controls.

Fire Protection

The Energy Commission staff reviewed the information provided in the AFC regarding on-site fire protection, which will be adequate for fighting incipient fires. The proposed fire protection system at the site will include fire alarms, detection systems, fire hydrants, water storage, and both primary electric and backup diesel water pumps and hose stations throughout the facility. Fixed fire suppression systems will be installed at pre-determined fire risk areas. The system will be designed and operated in accordance with National Fire Protection Association (NFPA) standards and recommendations. Sprinkler systems will be installed in the Control/Administration Building and Fire Pump Building, as required by NFPA requirements. Hand-held fire extinguishers will be located in accordance with NFPA 10 throughout the facility.

Energy Commission staff reviewed the information provided in the AFC to determine if available fire protection services and equipment would adequately protect workers, and to 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, the City of Blythe Fire Department and Riverside County Fire Department would provide fire support services, including trained firefighters and equipment for a sustained response.

During construction, portable fire extinguishers will be provided in accordance with Cal-OSHA requirements at locations including portable office spaces, welding and braising areas, flammable chemical storage areas, and mobile equipment. A 4,000-gallon water pumping truck will be located on-site until the permanent fire pump system is operational. (FSA, p. 4.14-11)

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 addressing fire protection at electric generating plants), and all Cal-OSHA requirements. Elements include both fixed and portable fire extinguishing systems. The BEP II fire protection system may also be interconnected to the existing BEP fire protection system. The firefighting water will be supplied from the raw water storage tank constructed as part of the BEP II project, with a minimum supply of 300,000 gallons dedicated for fire suppression purposes. The raw water storage tank has a holding capacity of 600,000 gallons, and make-up water will be provided by two on-site wells and pumps each capable of restoring water at a total maximum rate of 3,000 gallons/minute which is above the designed flow capacity of the 2,500 gpm fire protection pump.

The firewater pumping system consists of an electric motor-driven fire pump, an emergency backup driven by a diesel engine, and an electric jockey pump to maintain the pressure in the main fire loop. The fire loop pumps have a maximum capacity each of 2,500 gallons/minute to deliver water to the fire protection water piping network. The two electric well pumps at BEP I have a maximum capacity of 3,000 gallons/minute each. This system will provide more than an adequate quantity of fire-fighting water to facility fire hydrants, and automatic fire suppression (sprinkler/deluge) systems. A deluge type fire protection system will be provided for the turbine and generator bearing areas, lube oil lines, and lube oil tank and filter area.

Fire hydrants and portable fire extinguishers will be located throughout the power plant site at appropriate intervals according to code. The fire plant loop will also supply a vapor suppression system at the aqueous ammonia storage tank area.

In addition to the fixed fire protection system, smoke detectors, flame detectors, temperature detectors, and appropriate class of service portable extinguishers will be located throughout the facility at code-approved intervals. These systems are standard requirement by the NFPA and the UFC, and they will ensure adequate fire protection. (FSA, p. 4.14-11)

The Applicant will be required to provide the final Fire Protection and Prevention Program to the Compliance Project Manager (CPM) and to both the City of Blythe Fire Department and Riverside County Fire Department, prior to construction and operation of the project, to confirm the adequacy of the proposed fire protection measures.

CONDITION:

- ☑ The Project Owner shall submit fire protection plans for the construction and operation of the project. Conditions**: WORKER SAFETY-1 & WORKER SAFETY-2**.

Safety & Injury Prevention

Industrial environments are potentially dangerous. Workers could be exposed to chemical spills, hazardous waste, fires, moving equipment, and confined space entry and egress problems. It is important to have well-defined facility-specific policies and procedures, training, and hazard recognition and control to minimize work place hazards and to protect workers from unavoidable hazards. Energy Commission staff has reviewed the Applicant's proposed measures for protection of workers during construction and operation of the proposed project. These measures are described below. These measures are adequate to protect workers from work place hazards associated with the proposed project and to comply with applicable laws.

Construction: During the construction phase of the project, workers will be exposed to hazards typical of construction of a gas-fired combined cycle facility. Construction Safety Orders are published at Title 8 of the California Code of Regulations beginning with section 1502 (8 CCR § 1502, et seq.). These requirements are promulgated by Cal/OSHA and are applicable to the construction phase of the project. The Construction Injury and Illness Prevention Program will include the following:

A Construction Safety Program;
A Construction Personal Protective Equipment Program;
A Construction Exposure Monitoring Program;
A Construction Emergency Action Plan; and
A Construction Fire Protection and Prevention Plan.

Additional programs include General Industry Safety Orders (8 CCR § 3200-6184), Electrical Safety Orders (8 CCR §2299-2974) and Unfired Pressure Vessel Safety Orders (8 CCR § 450-544). The AFC includes adequate outlines of each of the above programs. (FSA, p. 4.14-6-7) Prior to construction of the project, detailed programs and plans will be provided pursuant to the Condition **WORKER SAFETY-1**.

CONDITION:

- ☑ The Project Owner shall prepare a Construction Safety and Health Program for the review and comment by the City of Blythe Fire Department and Riverside County Fire Department. Condition: **WORKER SAFETY-1**.

Operation: Upon completion of construction and prior to operation, the Applicant shall prepare the Operations and Maintenance Safety and Health Program pursuant to regulatory requirements of Title 8 of the California Code of Regulations, which will include the following programs and plans:

An Operation Injury and Illness Prevention Plan;
An Emergency Action Plan;
Hazardous Materials Management Program;
Operations and Maintenance Safety Program;
Fire Protection and Prevention Program (8 CCR § 3221); and;
Personal Protective Equipment Program (8 CCR §§ 3401-3411

Additional programs also include General Industry Safety Orders (8 CCR § 3200-6184), Electrical Safety Orders (8 CCR §2299-2974) and Unfired Pressure Vessel Safety Orders (8 CCR § 450-544). The AFC includes adequate outlines of each of the above programs. Cal/OSHA will review the Applicant's program and provide comments as a result of a consultation request. A Cal/OSHA representative will complete a physical survey of the site, analyze work practices, and assess those practices that may likely result in illness or injury. (FSA, p. 4.14-7-11)

CONDITION:

- ☑ The Project Owner shall prepare an Operations and Maintenance Safety and Health Program for the review and approval of Cal/OSHA and, as appropriate, review and comment of the City of Blythe Fire Department and Riverside County Fire Department. Condition: **WORKER SAFETY-2**.

Noise

Construction: The Applicant acknowledges the need to protect construction workers from noise hazards as well as the applicable laws and regulations relating to worker health and safety. The California Occupational Safety and Health Administration regulations provide the maximum noise level over an 8-hour work period is 90 dBA. Areas above 85 dBA need to be posted as high noise level areas and appropriate hearing protection will be provided. The Applicant will also adopt a hearing conservation program in accordance with the Cal-OSHA § 5097 Hearing Conservation Program.

CONDITION:

- ☑ The Project Owner shall institute an occupational noise control program to reduce exposure to high levels of construction noise. Condition: **NOISE-3.**

Operation: The Applicant recognizes the need to protect plant operating and maintenance personnel from noise hazards, and to comply with applicable laws and regulations. A measure to be implemented for noise-related impacts includes the above-mentioned Hearing Conservation Program.

CONDITION:

- ☑ The Project Owner shall conduct an occupational noise survey to identify noise hazardous areas and, if necessary, prepare mitigation in consultation with Cal/OSHA to reduce noise to prescribed limits. Condition: **NOISE-7**.

Finding

With the implementation of the Conditions of Certification, below, the project conforms to applicable laws related to worker safety.

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 Injury and Illness Prevention Program;
- A Construction Emergency Action Plan; and
- A Construction Fire Protection and Prevention Plan.

The Personal Protective Equipment 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 Protection and Prevention Plan shall be submitted to the City of Blythe Fire Department and the Riverside County Fire Department for review and comment prior to submittal to the CPM for approval.

Verification: At least 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 letter from the City of Blythe Fire Department and the Riverside County Fire Department stating that each has reviewed and commented on the Construction Fire Protection and 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 Protection and Prevention Program (8 CCR § 3221); and
- Personal Protective Equipment Program (8 CCR §§ 3401-3411).

The Operation Fire Protection Plan and the Emergency Action Plan shall also be submitted to the City of Blythe Fire Department and the Riverside County Fire Department for review and comment.

Verification: At least 30 days prior to the first start-up of combustion turbine, the project owner shall submit to the CPM for approval a copy of the Project Operations and

Maintenance Safety & Health Program. The project owner shall provide a letter from the City of Blythe Fire Department and the Riverside County Fire Department stating that each has reviewed and commented on the Operations Fire Protection and Prevention Plan and the Emergency Action Plan.

WORKER SAFETY-3 Prior to the delivery of anhydrous ammonia to the project site, the project owner shall train personnel at the BEP II facility to the level of Hazmat Technician that is required to assist the City of Blythe or Riverside County Fire Departments in the response to an anhydrous ammonia incident. The training shall meet or exceed that described in NFPA 472, PSHA 29 CFR 1910.120, and EPA 40 CFR part 311.

Verification: At least thirty (30) days prior to the delivery of hazardous materials to the site, the project owner shall provide the CPM with a letter indicating the number of employees that have been trained as Hazmat Technicians.

WORKER SAFETY-4 The project owner shall provide a portable automatic cardiac defibrillator on site during construction and operation.

Verification: At least 30 days prior to the start of site mobilization, the project owner shall submit to the CPM proof that a portable automatic cardiac defibrillator exists on site.

WORKER SAFETY-5 The project owner shall ensure that a CPM approved Safety Monitor(s) conducts an on-site safety inspection at least once a week during construction of permanent structures, and commissioning, of the power plant unless a lesser number of inspections are approved by the CPM. The CPM may also require a similar inspection and report concerning linear facilities.

The Safety Monitor shall keep the CBO fully informed regarding safety related matters and coordinate with the CBO concerning on-site safety inspections, and conduct a final safety inspection prior to issuance of the Certificate of Occupancy by the CBO. The Safety Monitor shall be retained until cessation of construction and commissioning activities, and issuance of the Certificate of Occupancy, unless otherwise approved by the CPM.

The Safety Monitor(s) shall also:

1. Inform the construction supervisors of any construction or commissioning problems that could pose a future danger to life or health, consulting with the CBO as necessary.
2. After consultation with the CBO, have the authority to temporarily stop construction or commissioning activities involving possible safety violations or unsafe conditions that may pose an immediate or future danger to life or health, until the problem is resolved to the satisfaction of the Safety Monitor and CBO.

3. Consult with the CBO to determine when construction may resume unless the problem is corrected immediately and to the satisfaction of the Safety Monitor and/or CBO.
4. Inform the CPM within 24 hours of any temporary halt in construction or commissioning activities.
5. Be available to inspect the site whenever necessary in addition to the minimum weekly basis during construction and commissioning as determined in consultation with the CBO and CPM.
6. Verify that a safety program for the project that complies with CAL-OSHA & Federal regulations related to power plant projects has been implemented.
7. Verify that all Federal and CALOSHA requirements are complied with during the construction and installation of all permanent structures (including safety aspects of electrical installations).
8. Verify that all construction and commissioning workers and supervisors receive adequate safety training.
9. Conduct accident and safety-related incident investigations, emergency response reports for injuries, and inform the CPM of all safety-related incidents.
10. Verify that all the plans identified in **WORKER SAFETY-1** are implemented.

The Safety Monitor shall be qualified regarding the following:

1. Safety issues related to equipment, pipelines, etc,
2. LORS applicable to workplace safety and worker protection
3. Workplace hazards typically associated with power production
4. Lock-out / tag-out and confined spaces control systems.

Verification: The project owner shall submit the Safety Monitor(s) resume(s) to the CPM for approval at least 30 days prior to site mobilization. One or more individuals may hold this position. The Safety Monitor shall submit in the MCR a monthly safety inspection report to include the following items:

1. Record of all employees trained for that month (all records shall be kept on site for the duration of the project);
2. Summary report of safety management actions that occurred during the month;
3. Report of any continuing or unresolved situations or incidents that may pose danger to life or health;
4. Report of accidents and injuries that occurred during the month.

LAWS, ORDINANCES, REGULATIONS & STANDARDS

WORKER SAFETY AND FIRE PROTECTION

APPLICABLE LAW	DESCRIPTION
FEDERAL	
Title 29 CFR §651 et seq.	Established the Occupational Safety and Health Act of 1970 to protect the health and safety of workers
Title 29 CFR §1910 et seq.	Contains the minimum occupational health and safety standards for general industry in the U.S.
Title 29 CFR §1926 et seq.	Contains the minimum occupational health and safety standards for construction industry in the U.S.
Title 29 CFR §1952.170-1952-175 et seq.	Gives California full enforcement responsibility for relevant federal occupational health and safety standards.
Title 49 CFR §192	U.S. Department of Transportation Pipeline Safety Regulations. Adopted by the California Public Utility Commission. Governs the California utilities on design, construction, testing, maintenance, and operation of piping systems.

STATE	
Title 8 CCR §5144	Requirements for respiratory protection programs for construction workers.
Title 8 CCR §1920 et seq.	Regulations for fire prevention during construction.
Title 8 CCR §450-560 et seq.	Applicable requirements of the Division of Industrial Safety, including Unfired Pressure Vessel Safety Orders, Construction Safety Orders, Electrical Safety Orders, and General Industry Safety Orders.
Title 8 CCR §1509, 1514-1522, 3203, 3220-3221, 3380-3390, 3401-3411	Outlines employer requirements for preparation of Illness and Injury Prevention Program, Emergency Action Plan, Fire Prevention Plan, and Personal Protective Equipment Program for construction and operations workers.
Health & Safety Code §25915-25919.7	Outlines requirements for Asbestos Management Plan including employee notification and handling procedures. Applies to presence of asbestos in the existing Units 1 & 2.
Labor Code §142.3	Authorizes the Occupational and Safety Health Board to establish safety standards.
Labor Code §6300 et seq.	Establishes the responsibilities of the Divisions of Occupational Health and Safety.
24 CCR §501 et seq.	Building code established to provide minimum standards to safeguard human life, health, property, and public welfare by controlling design, construction, and quality of materials of building.
California Public Utility Commission General Order No. 112-E	Additional restrictions to govern the California utilities on pipeline safety.
INDUSTRY STANDARDS	
Uniform Fire Code Standards	Contains provisions necessary for fire prevention and information about fire safety, special occupancy uses, special processes, and explosive, flammable, combustible and hazardous materials.

GENERAL CONDITIONS
INCLUDING
COMPLIANCE MONITORING AND CLOSURE PLAN

DEFINITIONS

To ensure consistency, continuity and efficiency, the following terms, as defined, apply to all technical areas, including Conditions of Certification:

SITE MOBILIZATION

Moving trailers and related equipment onto the site, usually accompanied by minor ground disturbance, grading for the trailers and limited vehicle parking, trenching for construction utilities, installing utilities, grading for an access corridor, and other related activities. Ground disturbance, grading, etc. for site mobilization are limited to the portion of the site necessary for placing the trailers and providing access and parking for the occupants. Site mobilization is for temporary facilities and is, therefore, not considered construction.

GROUND DISTURBANCE

Onsite activity that results in the removal of soil or vegetation, boring, trenching, or alteration of the site surface. This does not include driving or parking a passenger vehicle, pickup truck, or other light vehicle, or walking on the site.

GRADING

Onsite activity conducted with earth-moving equipment that results in alteration of the topographical features of the site such as leveling, removal of hills or high spots, or moving of soil from one area to another.

CONSTRUCTION

[From section 25105 of the Warren-Alquist Act.] Onsite work to install permanent equipment or structures for any facility. Construction does **not** include the following:

a. the installation of environmental monitoring equipment;

b. a soil or geological investigation;

c. a topographical survey;

d. any other study or investigation to determine the environmental acceptability or feasibility of the use of the site for any particular facility; or

e. any work to provide access to the site for any of the purposes specified in a., b., c., or d.

START OF COMMERCIAL OPERATION

For compliance monitoring purposes, “commercial operation” is that phase of project development that begins after the completion of start-up and commissioning, where the power plant has reached steady-state production of electricity with reliability at the rated capacity. For example, at the start of commercial operation, plant control is usually transferred from the construction manager to the plant operations manager.

COMPLIANCE PROJECT MANAGER RESPONSIBILITIES

A Compliance Project Manager (CPM) will oversee the compliance monitoring and shall be 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, and ownership or operational control;
4. documenting and tracking compliance filings; and
5. ensuring that the compliance files are maintained and accessible.

The CPM is the contact person for the Energy Commission and will consult with appropriate responsible agencies and the Energy Commission 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 staff and management.

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.

Pre-Construction and Pre-Operation Compliance Meeting

The CPM may schedule pre-construction and pre-operation compliance meetings prior to the projected start-dates of construction, plant operation, or both. The purpose of these meetings will be to assemble both the Energy Commission's and the 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 to confirm that they have been met, or if they have not been met, to ensure that the proper action is taken. In addition, these meetings shall 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 as a public record, in either the Compliance file or Docket 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 changes and the resulting staff or Energy Commission action.

PROJECT OWNER RESPONSIBILITIES

It is the responsibility of the project owner to ensure that the general compliance conditions and the conditions of certification are satisfied. The general compliance conditions regarding post-certification changes specify measures that the project owner must take when requesting changes in the project design, compliance conditions, or ownership. Failure to comply with any of the conditions of certification or the general compliance conditions may result in reopening of the case and revocation of Energy Commission certification, an administrative fine, or other action as appropriate.

COM-1, Unrestricted Access

The CPM, responsible Energy Commission staff, and delegate agencies or consultants, shall be guaranteed and granted unrestricted access to the power plant site, related facilities, project-related staff, and the files and 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.

COM-2, Compliance Record

The project owner shall maintain project files onsite, 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, all documents submitted as verification for conditions, and all other project-related documents.

COM-3, Compliance Verification Submittals

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.

Verification of compliance with the conditions of certification can be accomplished by:

1. reporting on the work done and providing the pertinent documentation in monthly and/or annual compliance reports filed by the project owner or authorized agent as required by the specific conditions of certification;
2. providing appropriate letters from delegate agencies verifying compliance;
3. Energy Commission staff audits of project records; and/or
4. Energy Commission staff inspections of mitigation or other evidence of mitigation.

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 involved condition(s) of certification by condition number and include 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.

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 submittals shall be addressed as follows:

Steve Munro (or successor)
Compliance Project Manager
California Energy Commission
1516 Ninth Street (MS-2000)
Sacramento, CA 95814

If the project owner desires Energy Commission staff action by a specific date, they shall so state in its submittal and include a detailed explanation of the effects on the project if this date is not met.

COM-4, Pre-Construction Matrix and Tasks Prior to Start of Construction
Prior to commencing construction, a compliance matrix addressing only those conditions that must be fulfilled before the start of construction shall be submitted by the project owner to the CPM. This matrix will be included with the project owner's first compliance submittal, and shall be submitted prior to the first pre-construction meeting, if one is held. It will be in the same format as the compliance matrix referenced 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 (e.g., 30, 60, 90 days) 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 construction.

Verification lead times (e.g., 90, 60 and 30-days) 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.

It is important that the project owner understand that the submittal of compliance documents prior to project certification is at the owner's own risk. Any pre-certification approval by Energy Commission staff is subject to change based upon the Final Decision.

EMPLOYEE ORIENTATION
Environmental awareness orientation and training will be developed for presentation to new employees during project construction as approved by Energy Commission staff and described in the conditions for Biological, Cultural, and Paleontological resources. At the time this training is presented, the project owner's representative shall present information about the role of the Energy Commission's delegate Chief Building Official (CBO) for the project. The role and responsibilities of the CBO to enforce relevant portions of the Energy

Commission Decision, the CBSC, and other relevant building and health and safety requirements shall be briefly presented. As part of that presentation, new employees shall be advised of the CBO's authority to halt project construction activities, either partially or totally, or take other corrective measures, as appropriate, if the CBO deems that such action is required to ensure compliance with the Energy Commission Decision, the CBSC, and other relevant building and health and safety requirements. At least 30 days prior to construction, the project owner shall submit the proposed script containing this information for CPM review and approval.

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 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.

<u>COM-5, Compliance Matrix</u>

The project owner shall submit a compliance matrix 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 compliance conditions in a spreadsheet format. The compliance matrix must identify:

1. the technical area;
2. the condition number;
3. a brief description of the verification action or submittal required by the condition;
4. the date the submittal is required (e.g., 60 days prior to construction, after final inspection, etc.);
5. the expected or actual submittal date;
6. the date a submittal or action was approved by the Chief Building Official (CBO), CPM, or delegate agency, if applicable;
7. the compliance status of each condition (e.g., "not started," "in progress" or "completed" (include the date); and
8. the project's preconstruction and construction milestones, including dates and status (if milestones are required).

Satisfied conditions do not need to be included in the compliance matrix after they have been identified as satisfied in at least one monthly or annual compliance report.

<u>COM-6, Monthly Compliance Report</u>

The first Monthly Compliance Report is due one month following the Energy Commission business meeting date on which the project was approved, unless otherwise agreed to by the CPM. The first Monthly Compliance Report shall include 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 five copies (or amount specified by Compliance Project Manager) 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, and should be submitted as attachments to the Monthly Compliance Report;
3. an initial, and thereafter updated, compliance matrix which shows the status of all conditions of certification;
4. a list of conditions that have been satisfied during the reporting period, and a description or reference to the actions which 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 with, 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;
10. any requests, with justification, to dispose of items that are required to be maintained in the project owner's compliance file; and
11. a listing of complaints, notices of violation, official warnings, and citations received during the month, a description of the resolutions of any resolved complaints, and the status of any unresolved complaints.

COM-7, Annual Compliance Report

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 identify the reporting period and shall contain the following:

1. an updated compliance matrix which shows the status of all conditions of certification (fully satisfied and/or closed conditions do not need to be included in the matrix after they have been reported as closed);

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, and should be submitted as attachments to the Annual Compliance Report;
4. a cumulative listing of all post-certification changes for the year 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 made 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 General 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 complaints, and the status of any unresolved complaints.

COM-8, Construction and Operation Security Plan

At least 14 days prior to commencing construction, a site-specific Security Plan for the construction phase shall be submitted to the CPM for approval. At least 30 days prior to the initial receipt of hazardous materials on-site, a site-specific Security Plan for the operational phase shall be submitted to the CPM for review and approval.

Construction Security Plan

The Construction Security Plan shall include the following:

1. site fencing enclosing the construction area;
2. use of security guards;
3. check-in procedure or tag system for construction personnel and visitors;
4. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency; and
5. evacuation procedures.

Operation Security Plan

1. The Operations Security Plan shall include the following:
2. permanent site fencing and security gate;
3. evacuation procedures;

4. protocol for contacting law enforcement and the CPM in the event of suspicious activity or emergency;
5. fire alarm monitoring system;
6. site personnel background checks, including employee and routine on-site contractors [Site personnel background checks are limited to ascertaining that the employee's claims of identity and employment history are accurate. All site personnel background checks shall be consistent with state and federal law regarding security and privacy.];
7. site access for vendors; and
8. requirements for Hazardous Materials vendors to prepare and implement security plans as per 49 CFR 172.800 and to ensure that all hazardous materials drivers are in compliance with personnel background security checks as per 49 CFR Part 1572, Subparts A and B.

In addition, the Security Plan shall include one or more of the following in order to ensure adequate perimeter security:

1. security guards;
2. security alarm for critical structures;
3. perimeter breach detectors and on-site motion detectors; and
4. video or still camera monitoring system.

In addition, in order to determine the level of security appropriate for this power plant, the project owner shall prepare a Vulnerability Assessment that is consist with guidelines including but not limited to the:

- Chemical Accident Prevention Alert regarding Site Security (EPA 2000),
- Department of Justice Chemical Facility Vulnerability Assessment Methodology (US DOJ 2002),
- North American Electric Reliability Council Security Guidelines for the Electricity Sector (NAERC 2002),
- U.S. Department of Energy Vulnerability Assessment Methodology for Electric Power Infrastructure (DOE 2002), and the
- California Energy Commission.

The level of security to be implemented is a function of the likelihood of an adversary attack, the likelihood of adversary success in causing a catastrophic event, and the severity of consequences of that event. This Vulnerability Assessment will be based, in part, on the use and storage of certain quantities of acutely hazardous materials as described by the California Accidental Release Prevention Program (Cal-ARP, Health and Safety Code section 25531). Thus, the results of the off-site consequence analysis prepared as part of the Risk Management Plan (RMP) will be used to determine the severity of consequences of a catastrophic event and hence the level of security measures to be provided.

The Project Owner shall fully implement the security plans and obtain CPM approval of any substantive modifications to the Security Plan. The CPM may authorize modifications to these measures, or may recommend additional measures depending on circumstances unique to the facility, and in response to industry-related security concerns.

COM-9, Confidential Information

Any information that the project owner deems confidential shall be submitted to the Energy Commission's Docket 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.

COM-10, Department of Fish and Game Filing Fee

Pursuant to the provisions of Fish and Game Code Section 711.4, the project owner shall pay a filing fee in the amount of $850. The payment instrument shall be provided to the Energy Commission's Project Manager (PM), not the CPM, at the time of project certification and shall be made payable to the California Department of Fish and Game. The PM will submit the payment to the Office of Planning and Research at the time of filing of the notice of decision.

COM-11, Reporting of Complaints, Notices, and Citations

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 inquiries 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 of all complaint forms, notices of violation, notices of fines, official warnings, and citations, within 10 days of receipt, to the CPM. Complaints shall be logged and numbered. All complaints shall be recorded on the complaint form (Attachment A) or an equivalent.

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 at the end of a project's life, 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 remains accountable for implementing the on-site contingency plan. It can also include unplanned closure where the project owner is unable to implement the contingency plan, and the project is essentially abandoned.

GENERAL CONDITIONS FOR FACILITY CLOSURE

COM-12, Planned Closure

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 twelve months prior to commencement of closure activities (or other period of time agreed to by the CPM). 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, local/regional plans in existence at the time of facility closure, and applicable conditions of certification.

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.

In addition, 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.

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 Energy Commission approval of the facility closure plan is obtained.

COM-13, Unplanned Temporary Closure/On-Site Contingency Plan

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 that 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 the analysis 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 twelve 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).

COM-14, Unplanned Permanent Closure/On-Site Contingency Plan

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 unlikely 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.

CBO Delegation and Agency Cooperation

In performing construction monitoring of the project, Commission staff acts as, and has the authority of, the Chief Building Official (CBO). Commission staff may delegate CBO responsibility to either an independent third party contractor or the local building official. 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.

Commission staff may also seek the cooperation of state, regional and local agencies that have an interest in environmental control 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.

Moreover, to ensure compliance with the terms and conditions of certification and applicable LORS, delegate agencies are authorized to take any action allowed by law in accordance with their statutory authority, regulations, and administrative procedures.

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 1230 et seq., 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 current law or regulations.

Informal Dispute Resolution Procedure

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 this procedure for resolving a dispute. Disputes may pertain to actions or decisions made by any party including the Energy Commission's delegate agents.

This procedure may precede the more formal complaint and investigation procedure specified in Title 20, California Code of Regulations, section 1230 et seq., 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 procedure 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 referred to the full Energy Commission for consideration via the complaint and investigation process. The procedure for informal dispute resolution is as follows:

Request for Informal Investigation

Any individual, group, or agency may request that the Energy Commission 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 and, within seven working days of the CPM's request, provide a written report of the results of the investigation, including corrective measures proposed or undertaken, to the CPM. Depending on the urgency of the noncompliance matter, the CPM may conduct a site visit and/or request the project owner to provide an initial report, within 48 hours, followed by a written report filed within seven days.

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 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; and
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 which fairly and accurately identifies the positions of all parties and any conclusions 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.

<u>Formal Dispute Resolution Procedure-Complaints and Investigations</u>

If either the project owner, Energy Commission staff, or the party requesting an investigation is not satisfied with the results of the informal dispute resolution process, such party may file a complaint or a request for an investigation with the Energy Commission's General Counsel. Disputes may pertain to actions or decisions made by any party including the Energy Commission's delegate agents. Requirements for complaint filings and a description of how complaints are processed are in Title 20, California Code of Regulations, section 1230 et seq.

The Chairman, upon receipt of a written request stating the basis of the dispute, may grant a hearing on the matter, consistent with the requirements of noticing provisions. The Energy Commission shall have the authority to consider all relevant facts involved and make any appropriate orders consistent with its jurisdiction (Cal. Code Regs., tit. 20, §§ 1232-1236).

POST CERTIFICATION CHANGES TO THE ENERGY COMMISSION DECISION: AMENDMENTS, OWNERSHIP CHANGES, INSIGNIFICANT PROJECT CHANGES AND VERIFICATION CHANGES

The project owner must petition the Energy Commission pursuant to Title 20, California Code of Regulations, section 1769, in order to delete or change a condition of certification, modify project design, operation or performance requirements, and to transfer ownership or operational control of the facility.

A petition is required for amendments and for insignificant project changes as specified below. 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 Docket in accordance with Title 20, California Code of Regulations, section 1209.

The criteria that determine which type of approval process applies are explained below.

Amendment
A proposed project modification will be processed as an amendment if it alters the intent or purpose of a condition of certification, has potential for significant adverse environmental impact, or may violate applicable laws, ordinances, regulations or standards. The full Commission must approve formal amendments. The project owner shall file a petition in accordance with Title 20, California Code of Regulations, section 1769 (a).

Change of ownership
Change of ownership or operational control also requires that the project owner file a petition, and obtain Commission approval, pursuant to section 1769 (b).

Insignificant Project Change
If a proposed modification does not alter the intent or purpose of a condition of certification, does not have potential for significant adverse environmental impact, does not violate applicable laws, ordinances, regulations, or standards, or does not result in an ownership change, it will be processed in accordance with Section 1769(a)(2). In this regard, as specified in Section 1769(a)(2), Commission approval is not required.

The CPM shall file a statement that staff has made such a determination with the Commission Docket and mail a copy of the statement to every person on the project's post-certification mailing list.

Any person may file an objection to staff's determination within 14 days of service on the grounds that the modification does not meet the criteria in section 1769 (a)(2). If an objection is received, the petition must be processed as a formal amendment to the final decision and must be approved by the full Commission at a noticed business meeting or hearing.

Verification Change

A verification may be modified by the CPM without requesting an amendment to the decision if the change does not conflict with intent or purpose of the conditions of certification and provides an effective alternate means of verification.

COM-6, KEY EVENTS LIST

PROJECT: Blythe II Power Project

DOCKET # 02-AFC-1

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	
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	

COMPLAINT REPORT/RESOLUTION FORM

PROJECT NAME: Blythe II Power Project AFC Number: 02-AFC-1C
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 Energy Commission 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.)

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CALIFORNIA ENERGY COMMISSION

1516 Ninth Street
Sacramento, CA 95814
800-822-6228
www.energy.ca.gov

ERRATA RE PRESIDING MEMBER'S PROPOSED DECISION	(For Docket Unit Use)
BLYTHE ENERGY PROJECT II APPLICATION FOR CERTIFICATION DOCKET NO. 02-AFC-1	

Background: On October 21, 2005, the Committee publicly issued its Presiding Member's Proposed Decision (PMPD), beginning a 30-day public comment period. On November 10, 2005, the Committee conducted a public hearing to receive comments from the active parties on the PMPD. On December 13, 2005, the Committee an additional public hearing on agency and public comments filed at or after the close of the comment period. The following corrections and changes represent the Committee's Errata to the PMPD.

RESPONSE TO APPLICANT & STAFF COMMENTS

Air Quality

Page 17, first paragraph: Correct date for FDOC.

Page 27, under PSD Review: Correct reference to MDAQMD PSD review which is administered by the U.S. EPA.

Biology

Page 59 – Correct the reference to Western as the proponent of the DSWTP by stating that the agency overseeing the DSWTP is the Imperial Irrigation District (IID).

Page 70, under LORS – Supplement the list of applicable state and local LORS.

Page 67-68, **BIO-11** -- Add the Compliance Project Manager (CPM) to the list of regulatory agencies.

Cultural Resources

Page 74, fourth paragraph, second sentence -- Clarify the reference to cultural resource CA-Riv-6725H.

Page 74, fifth paragraph, first sentence -- Clarify the reference to cultural resource CA-Riv-6370H.

Page 82, **CUL-6** & page 84, **CUL-9** - Conform to agreed-upon language about project owner requests to reduce monitoring by a resource specialist and the timing of blessing ceremonies, respectively.

Hazardous Materials

Page 111 -- Correct **HAZ-1** to include agreed-upon text about the types and quantities of hazardous materials to be stored on-site.

Page 114 -- Correct **HAZ-11** to include agreed-upon text concerning the ammonia sensor for the inlet air cooling system.

Socioeconomics

Page 165, **SOCIO-2** -- Include agreed-upon Verification.

Traffic and Transportation (Aviation Safety)

Page 186 – Correct reference to author of May 17, 2005 letter to Florida Power and Light.

Waste Management

Page 229 –**WASTE-6**, change "excavation" to "earth disturbance for construction purposes."

Water Quality

Page 234 - Add language that BEP II would monitor accumulated sediment levels as part of their Drainage, Erosion, and Sediment Control Plan, even though removal of accumulated sediments in the retention basin is the responsibility of the BEP I project owner.

Page 239 -- **WATER QUALITY-5** should be modified to reflect the use of RWQCB permitted evaporation ponds for discharge of wastewater is only during periods of ZLD outages. ZLD plan submittal shall be 60 days prior to ZLD construction.

Page 241 – Add **WATER QUALITY 7** implementing Waste Discharge Requirements (WDR) on the back-up evaporation ponds.

Water Resources

Page 273, **WATER RESOURCES-1(a)** - Correct regarding soil types for Best Management Practices.

Reliability

Page 312, first paragraph 1 – Update the NERC reported availability factor for combined cycle to 2005 figures.

Miscellaneous

Typographical and other minor, non-substantive corrections.

RESPONSE TO EPA COMMENTS

The U.S. EPA filed comments on November 23, 2005, following the close of the public comment period for the PMPD. The EPA attached a copy of a December 2002 letter to the Mojave Desert Air Quality Management District (MDAQMD) asserting deficiencies in the District's Preliminary Determination of Compliance on the project.

In its comments on the PMPD, the EPA re-asserts two of those deficiencies, related to the use of road paving offsets for PM_{10} and the use of interpollutant trade-offs without EPA approval.

Road Paving as a PM_{10} Offset

By way of historical background, the MDAQMD released its Preliminary Determination of Compliance (PDOC) in 2002, which was followed by a public comment period. The EPA's December 2002 comments were made on the PDOC.

The Energy Commission staff coordinated its analysis with the District's for the PDOC. On November 14, 2003, the Staff released it Preliminary Staff Assessment (PSA). The PSA states in several places Staff's concern that the EPA comments on the invalidity of road paving offsets for PM_{10} and the necessity of EPA approval for interpollutant trade-offs, particularly the questionable use of road paving for SOx, bring into question compliance with federal requirements and would necessitate obtaining alternate, valid PM_{10} offsets. (PSA, pp. 4.1-26, 27, 28 & 29) Staff concluded in its PSA that it did not yet consider the Applicant's proposed mitigation to be viable. (PSA, p. 4.1-28) The PSA also notes, however, that an Applicant filing to the District indicated that no alternate PM_{10} offsets have been identified. (PSA, p. 4.1-26)

The MDAQMD released its Final Determination of Compliance (FDOC) on May 3, 2004, approximately seven months after the Staff's PSA. The FDOC incorporated changes the District chose to make in response to the comments on the PDOC and evaluated whether and under what conditions the proposed project will comply with the applicable rules and regulations.

Taking into consideration the FDOC and its own analysis, the Staff subsequently released its Final Staff Assessment (FSA) on April 29, 2005, again addressing road paving as offsets for PM_{10} and as interpollutant offsets for SOx. Staff noted that the MDAQMD would allow road paving to satisfy 126 tons-per-year PM_{10} offset requirement. Using outdated 1998 EPA emission factors, the MDAQMD calculated that 9,280 linear feet of roads would need to be paved. The FSA stated the MDAQMD used the outdated emission factors because it was the methodology in place at the time the Applicant first proposed the project in 2002. Staff stated in its FSA that the EPA offered no further comments on the matter. (FSA, pp. 4.1-27 & 28)

In its FSA, Staff advocated using EPA's updated emission factors and calculated that offset value of the proposed road paving would be reduced from 126 to 70 tons-per-year of PM_{10}. Staff reiterated its reservations about using dust control to mitigate for combustion-related particulate matter and that paving public roads is not a source category that is normally subject to permitting in the District. But Staff acknowledged that the MDAQMD had previously used road paving offsets in earlier projects, including BEP I. (FSA, p. 4.1-30) Staff concluded that with a recommended condition (PMPD Condition **AQ-C9**) the project's emissions, including PM_{10} and SOx, would be fully mitigated by the proposed offsets, plus additional offsets required by the Condition.

During the Committee's Prehearing Conference in July 2005, the Applicant did not indicate that it intended to contest Staff's FSA Air Quality section when it would be presented as Staff's testimony at subsequent Evidentiary Hearings in August 2005. The Committee's review of the Commission Docket Unit records does not disclose any written comments from the EPA in this proceeding on this matter following the District's FDOC, the Staff's FSA, or at the Evidentiary Hearings. Based upon the evidentiary record, the Committee prepared the PMPD and incorporated the Air quality Conditions recommended in the Staff's FSA.

The EPA's comments specifically state that the road paving offsets in the FDOC are "seriously flawed" in that they do not satisfy the fundamental requirements for NSR offsets to be surplus, quantifiable, permanent, and federal enforceable. The December 26, 2002, EPA letter stated, "To ensure the creditability of non-traditional ERC's, such as those generated by road paving, the SIP [State Implementation Plan] must contain an approved protocol for quantifying and guaranteeing the permanence, surplus nature and enforceability of such credits. The PM_{10} credits in the BEPII PDOC cannot be allowed to offset the PM_{10} increases. Therefore, you must required the applicant to obtain and publicly notice valid PM_{10} ERC's before issuing the FDOC." (p. 2)

With respect to the use of road paving as an offset for PM_{10}, the established evidentiary record in the BEP II proceeding discloses that (1) the MDAQMD is in attainment of federal PM_{10} air quality standards, but is non-attainment for the State standards, (2) in this desert setting fugitive dust is the major contributor to PM_{10} violations of State air quality standards, (3) road paving will mitigate for that contribution, (4) there are not sufficient alternative, combustion-source PM_{10} offsets in this desert setting to offset this project, and (5) road paving has previously been used as a valid offset for PM_{10} for BEPI.

The PMPD incorporated air quality conditions **AQ-1** through **AQ-54**, which were derived from the MDAQMD's FDOC. Condition **AQ-18** speaks to the Applicant's obtaining and surrendering to the MDAQMD sufficient valid offsets, including PM_{10}, before the start of construction of the equipment (gas turbine) to which the offset is related. The PMPD also includes a Staff-recommended Condition **AQ-C9**, specifically referring to the road paving PM_{10} offsets obtained from the Colorado River Indian Tribe. **AQ-C9** expressly provides, "The ERC [offset] list shall contain evidence that the MDAQMD has determined that the ERCs are real, enforceable, surplus, permanent, and quantifiable. The project owner may request [Energy Commission] CPM approval for any substitutions or modifications of credits listed below." **AQ-C9** also provides that such a change in the ERC list must be consistent with applicable federal and state laws and not cause the project to result in a significant environmental impact.

The Commission has re-reviewed the PMPD Air Quality Conditions to determine whether they assure compliance with all federal air quality requirements. We do not read the EPA letters to state that road paving ***cannot*** be a valid offset for PM_{10}. The EPA's oral comments at the Committee's December 13, 2005, Workshop confirm this view. EPA's December 2002 letter states that to "ensure the creditability of non-traditional ERC's, such as those generated by road paving," there must an "approved protocol for quantifying and guaranteeing the permanence, surplus nature and enforceability of such credits." Condition **AQ-C9** requires the Applicant's showing that these non-traditional road paving offsets offered in this proceeding be "real, enforceable, surplus, permanent, and quantifiable." To assure compliance with federal law, we believe that Condition **AQ-C9** should be changed to read, "The ERC list shall contain evidence that the MDAQMD <u>and the U.S. EPA have</u> determined that the ERCs are real, enforceable, surplus, permanent, and quantifiable. … The CPM, in consultation with the District <u>and the U.S. EPA</u>, may approve any such change to the ERC list ….. " The Verification to **AQ-C9** will be made consistent with these changes.

The Commission notes that the EPA's December 2002 letter also stated that the MDAQMD was to require the applicant to obtain and publicly notice valid PM_{10} ERC's before issuing the FDOC. Our record appears to confirm that between the PDOC and the FDOC the road paving offsets were identified and quantified with greater specificity, but they were not actually obtained nor subject to a public review process before the MDAQMD's issuance of the FDOC. Nor did such a process occur prior to the Committee's release of the PMPD. Rather, for our purposes, the Commission is following its practice of requiring the Applicant's identification of specific offsets in our proceeding and awaiting the District's public process to validate and thereafter accept the proposed offsets. In this proceeding, such a practice remains appropriate since there are numerous conditions precedent to the commencement of construction of this project, some of which arise from circumstances in the State's electricity market and others that are specified in our Conditions of Certification. Our evidentiary record discloses that there are ample publicly used, unpaved roads that are candidates for use as offsets. Plus, road paving offsets were called out as PM_{10} offsets in our Blythe I Decision and thereafter identified and validated in the District's public process. Therefore, the Commission believes that it is appropriate for our Decision to regard the District's process to validate the road paving offsets as one of series of events which will take place at the appropriate time and with the appropriate process, while meeting the requirements of Condition **AQ-C9** to assure substantive compliance with State and federal law.

Therefore, the Commission believes that road paving is an appropriate offset for this project's PM_{10} emissions. Consequently, the next issue is the adequacy of the amount of proposed road paving to offset the PM_{10} emissions. The Commission favors the use of the more up-to-date emission factors in calculating the amount of road paving to create sufficient offsets. The Commission understands that any road paving offsets submitted to the District will be scrutinized in an open, public process for the specific road location and the amount of traffic in order to calculate the resulting offset.

Since Staff's testimony states that there are as many as 36 miles of publicly used Indian reservation roads which could be paved, the Commission has confidence that the Applicant can provide the MDAQMD a sufficient additional inventory of potential paving to satisfy this offset requirement. Thus, the Commission will amend the table appearing in Air Quality Condition **AQ-C9** to include an additional, but as-yet unidentified, of Colorado River Indian Tribe Road Paving as a required offset source for PM10. The Commission is aware that since road paving is not a standard offset source the MDAQMD must use a public notification procedure in its review and approval of road paving as a valid offset. We anticipate this process will identify the specific roads to be paved and the exact linear footage required to comply with the updated emission factor calculation method.

<u>Interpollutant Tradeoffs</u>

With respect to EPA's comment regarding approval of interpollutant trade-offs, the Commission believes that the requirement of MDAQMD Rule 1305(B)(6)(a) needs to be expressly acknowledged in the Decision. The Rule provides:

> Emission reductions of one type of air pollutant may be used as offsets of another type of air pollutant upon approval of the APCO, in consultation with CARB and the approval of the USEPA, on a case-by-case basis as long as the following apply:
>
> (i) The trade must be technically justified, and
>
> (ii) The applicant must demonstrate, to the satisfaction of the APCO, that the combined effect of the offsets and emission increases from the new or modified facility will not cause or contribute to a violation of an ambient air quality standard.

Referring to EPA's December 2002 letter commenting on the PDOC, EPA stated that it has not approved a methodology for determining the 1-to-1 interpollutant trade-off ratios used in the PDOC. EPA states further, "Several methods might be acceptable in conjunction with other considerations for this specific project." (pp. 2, 3) Taking all the EPA's comments together, the Commission finds that the issue is not whether an appropriate interpollutant trade-off ratio can be established in this case, but the necessity and adequacy of the Applicant's demonstration to the MDAQMD and, thereafter, the EPA of a technically justifiable ratio.

Thus, the Commission believes that Air Quality Condition **AQ-18** needs to be amended to expressly acknowledge the required approval of the EPA for the interpollutant trade-off ratios, and will use Staff-suggested language to do so.

<u>RESPONSE TO COMMENTS FROM THE CENTER ON RACE, POVERTY & THE ENVIRONMENT</u>

The Center on Race, Poverty & the Environment (Center), in Delano, California, filed timely comments on the PMPD on behalf of unnamed residents of Blythe and urged the Commission to deny certification of the facility. The Center is not a party to the proceeding, and these comments are the Center's first communication with the Commission on this project since the AFC was filed on February 19, 2002.

Citing the PMPD's rejection of dry cooling as preferable to the proposed wet cooling with degraded groundwater, the Center asserts environmental justice concerns. Specifically, the Center asserts that use of wet cooling instead of dry cooling exposes the community to cooling tower drift and non-criteria air pollutants, creates thermal plumes interfering with air traffic, and causes significant water use in the desert. The Center concludes that the PMPD rejects dry cooling as mitigation for alleged project impacts merely because the Applicant objected to it.

In addition, the Center asserts that the Commission has not sufficiently fulfilled the CEQA analysis on air quality matters, including the use of road paving as an offset for PM_{10} emissions and the ineffectiveness of road paving to mitigate combustion-created $PM_{2.5}$ emissions. The Center also claims that ammonia slip is insufficiently controlled and that the PMPD should require an alternative to the use of an ammonia-based refrigerant for cooling inlet air. Lastly, the Center claims that the PMPD's use of a 6-mile radius study area for cumulative project air quality impacts is arbitrarily undersized.

Wet Cooling versus Dry Cooling

The PMPD extensively discusses the merits of the wet cooling versus dry cooling issue. (PMPD, pp. 260 - 264) Energy Commission staff strongly advocated the use of dry cooling at the project location, or Staff's suggested alternative locations, to avoid the use of water for cooling. There was extensive back-and-forth testimony between the Staff and Applicant at the evidentiary hearings which addressed the adequacy of dry cooling in the desert setting, the size of dry cooling towers that approached comparable cooling capacity, operational flexibility of dry cooling, capital costs, operational costs and inefficiencies, visual impacts, noise impacts, and plume impacts upon aviation. On balance, when compared to the use of degraded groundwater and wet cooling, the evidence convincingly supported the use of wet cooling and the rejection of dry cooling. The use of drift eliminators (Condition **PUBLIC HEALTH-1**) and management of cooling tower water quality (Conditions **PUBLIC HEALTH-2** and **WATER QUALITY-3**) support the PMPD's findings that wet cooling will not cause significant environmental impacts or public health impacts to any neighboring resident or nearby community.

Road Paving PM10 Offsets

The Commission has extensively discussed road paving as PM_{10} offsets, above, in response to the EPA comments. We are calling for road paving credits to be calculated using the more up-to-date emission factors promulgated by the EPA. The PMPD's discussion of road offsets acknowledges the size difference of combustion-produced particulates and dust particulates from the use of unpaved roadways. The evidentiary record discloses that the current violation of the PM_{10} ambient air quality standards in the MDAQMD results from blowing dust. There are not sufficient combustion sources, in the form of industrial facilities, in the desert to themselves cause a violation of air quality standards or to provide combustion-based PM_{10} offsets.

Under these circumstances, the use of the road paving PM_{10} offsets is appropriate and adequate mitigation for the project's PM_{10} emissions. Rather than deferring an analysis of the adequacy of road paving *as mitigation* until after certification as the Center asserts, the Commission has analyzed and confirmed the adequacy of road paving as effective mitigation. However, condition **AQ-C9** acknowledges that the adequacy *of the number of feet* of proposed paving must await the Applicant's submittal of its offset package to the MDAQMD and the public process for their review. In the meantime, the Commission has added clarification that such a calculation will be done with the EPA's updated emission factors, which would add to the effectiveness of the offsets. (PMPD, pp. 21 – 25)

PM2.5

With regard to $PM_{2.5}$, the PMPD discusses that the MDAQMD does not need to develop an air quality management plan for $PM_{2.5}$ because the Mojave Desert Air Basin was designated in 2004 as an area that is either unclassified or attains both the state and federal $PM_{2.5}$ standards. The maximum 24-hour concentration occurring between 1999 and 2003 was 38.0 $\mu g/m^3$ compared to the 1997 U.S. EPA standard of 65 $\mu g/m^3$. The record supports the finding that there is not a significant $PM_{2.5}$ impact from the project. (PMPD, p. 22)

Ammonia Slip Limit

The ammonia slip from the project was determined by the MDAQMD to be limited to 10 ppm. In this proceeding, the Energy Commission staff had advocated in its Preliminary Staff Assessment that ammonia slip be limited to 5 ppm, largely on the basis that since catalyst vendors can virtually assure ammonia slip at or below 5 ppm that the Blythe project be limited to the best performance available. Staff has made this recommendation in other power plant proceedings as well. The EPA and California Air Resources Board support the 5 ppm limitation in this case.

The MDAQMD did not find it necessary to control ammonia slip down to 5 ppm largely because the area is ammonia rich so that "tighter" controls would not produce a benefit in the macro environmental setting. Consequently, the MDAQMD set a limit of 10 ppm in its Final Determination of Compliance.

Typically, the Staff holds public workshops to discuss with other agencies, the Applicant and public the analysis and recommended conditions in its Preliminary Staff Assessment and its Final Staff Assessment. These workshops are not transcribed. The Commission observes from the change in language from the PSA to the FSA, that the Staff's recommended 5 ppm ammonia slip condition had changed into an acknowledgement of the MDAQMD 10 ppm ammonia slip limit, *averaged over one hour*, but suggested a 5 ppm performance limit *averaged over 24 hours*. If the 5 ppm limit were exceeded the Applicant was to replace or repair the ammonia injection grid, unless the Applicant could demonstrate that the exceedance was a "false trigger." The Applicant agreed to the Staff's proposed condition at the evidentiary hearings. As worded, Condition **AQ-C10**, which fully incorporates Staff's recommendation, would allow the Applicant to show that the ammonia slip "consistently" remained below 5 ppm and that the initial exceedance was a false trigger to avoid repair or replacement of the ammonia injection grid.

The Center objects to the use of “consistently” since the condition does not define its meaning and argues that if 5 ppm is achievable it should be required without exception.

In addressing the Center’s comments, the Commission must view the larger context into which Condition **AQ-C10** fits. To comply with applicable air quality laws, the project must meet the MDAQMD limit of 10 ppm. However, Staff believes that ammonia slip above 5 ppm potentially contributes to the formation of secondary PM_{10}. Yet, Staff’s testimony is that secondary particulates are probably a minor fraction of overall PM_{10} since there are few major sources of PM_{10} precursors. The EPA December 2002 comments on the PDOC also recommended a 5 ppm limit based upon guidelines from the California Air Resources Board. (PMPD, p. 26)

The Commission agrees with the Center that the word “consistently” as applied to operating below 5 ppm creates a standard-less standard. For example, does that mean below 5 ppm for 4 out of 5 operational days, or 19 out of 20? Or, is “consistently” measured as other than time? The Commission’s compliance monitoring unit has no clear definition of what “consistently” means through the language of this Condition. However, the concept of a “false trigger” is familiar to our CPMs who must deal with myriad power plant systems that must meet performance standards with machinery, pumps, valves, sensors, etc., that do not work perfectly 100% of the time.

Therefore, the Commission will delete from Condition **AQ-C10** the reference to “consistently” but continue the language that affords a project owner an opportunity to demonstrate, with any relevant information, that an exceedance of a performance standard was the result of a false trigger.

Ammonia Refrigerant

The Applicant has chosen to use ammonia as the refrigerant for the inlet cooling system. The Center’s comments focus on the PMPD discussion that the Applicant should consider an alternative refrigerant that would have fewer potential offsite effects in the event of an accidental release. The Center asks the Commission to require the use of the alternative refrigerant unless the Applicant shows it is infeasible. The Commission staff has historically disfavored the use of anhydrous ammonia for any power plant uses and thoroughly evaluated its use as the refrigerant for the project. As discussed in the PMPD, the BEP I project already uses ammonia for its inlet chiller.

The BEP II project is designed to use about 15 percent of the amount of ammonia as BEP I. After its initial charge of the cooling system, the project is expected to require about 300 pounds of additional recharge ammonia every four to five years. Staff also calculated the potential to affect the Mesa Verde community, the largest concentration of residences 2.2 miles from the project. Staff calculated that the probability of a significant occurrence affecting Mesa Verde was 2 in 10,000,000. Staff calculated that a significant occurrence on Interstate 10, which is closer than Mesa Verde, was 2 in 1,000,000. (PMPD, p. 104) At the evidentiary hearings, public witnesses brought in a local newspaper story about the shut-down of Interstate 10, without injuries or fatalities, due to an ammonia incident at BEP I (Palo Verde Valley Times, September 29, 2004)

The PMPD recognizes that there could be benefits from the use of the alternative refrigerant and asks the Applicant to consider it. However, the Commission also imposes numerous conditions, not initially in the BEP I Decision, related to the use of the ammonia refrigerant, including preparation of an Ammonia Refrigeration Hazard Reduction Plan under EPA guidelines as well as automatic fire suppression systems and closure devices. (PMPD, pp. 104 – 107) See **HAZ-8, HAZ-10** and **HAZ-11**. On this basis, the Commission has properly determined that the use of ammonia refrigerant by the project does not create a significant impact nor significant public health and safety risk.

Cumulative Impacts Study Area

Lastly, the Center comments that the PMPD's use of a 6-mile radius for consideration of cumulative impacts is insufficient pursuant to CEQA and that the cumulative air quality analysis ignored the neighboring BEP I facility. First, the Commission's use of a 6-mile radius study area for cumulative impacts is a practice that was developed over decades of past proceedings because it consistently demonstrated for our CEQA-equivalent process the extent of potential public health and public safety impacts. Historically, air quality modeling had shown that air quality and public health impacts, if they occur, do so within a 6-mile radius. As applied, the Blythe II cumulative impact study area embraces all significant population centers for our public health analysis. There is no evidence in the record that suggests that the study area used in the proceeding and discussed in the PMPD was insufficient to capture all potential impacts.

The Center comments also assert that the PMPD air quality analysis ignored the neighboring BEP I facility. Yet, the PMPD discloses that the BEP I facility was considered as part of the "existing" environmental setting in which the potential direct air quality impacts of the BEP II projects were analyzed as well as potential cumulative air quality impacts from both BEP I and BEP II. The MDAQMD had no records identifying any other potential and/or permitted projects that could have interacted with the project and warranted analysis. (PMPD p. 27)

RESPONSE TO COMMENTS FROM THE PALO VERDE COLLEGE SMALL BUSINESS DEVELOPMENT CENTER

Quenton Hanson, Executive Director of the Small Business Development Center, submitted email comments calling for the inclusion of a Socioeconomics condition requiring the Applicant and its contractors to recruit local employees and procure materials locally when available and to the extent not prohibited by law. Such a condition was included in the Commission's Decision on the BEP I project as SOCIO-2. In public comments at the evidentiary hearings, Mr. Hanson has described the success of the local hiring and purchasing condition for the local Blythe economy and residents during BEP I construction and operation without any material hindrance to the construction and operation of the BEP I project. Local hiring and purchasing contribute to the Commission's finding that the project will provide a degree of economic benefits to the local area. Thus, since the Applicant and Staff concur, the Commission will include in the Socioeconomics section of this Decision a condition identical to SOCIO-2 in the BEP I Decision.

CALIFORNIA ENERGY COMMISSION

1516 Ninth Street
Sacramento, CA 95825-5512
800-822-6228
www.energy.ca.gov

ADOPTION ORDER

Order No. 05-1214-08

BLYTHE ENERGY PROJECT, PHASE II
APPLICATION FOR CERTIFICATION
DOCKET NO. 02-AFC-1

This Order adopts the Commission Decision on the Blythe Energy Project, Phase II. It incorporates the Presiding Member's Proposed Decision (PMPD) and the Committee Errata incorporated herein. The Commission Decision is based upon the evidentiary record of these proceedings and considers the comments received at the December 14, 2005, business meeting. The text of the attached Commission Decision contains a summary of the evidence presented and the rationale for the findings reached and Conditions imposed.

This Order adopts by reference the text, Conditions of Certification, and Compliance Verifications, contained in the Commission Decision. It also adopts specific requirements contained in the Commission Decision which ensure that the proposed facility will be designed, sited, and operated in a manner to protect environmental quality, to assure public health and safety, and to operate in a safe and reliable manner.

FINDINGS

The Commission hereby adopts the following findings in addition to those contained in the accompanying text:

1. The project will provide a degree of economic benefits and electricity reliability to the local area.

2. The Conditions of Certification contained in the accompanying text, if implemented by the project owner, ensure that the project will be designed, sited, and operated in conformity with applicable local, regional, state, and federal laws, ordinances, regulations, and standards, including applicable public health and safety standards, and air and water quality standards.

3. Implementation of the Conditions of Certification contained in the accompanying text will ensure protection of environmental quality and assure reasonably safe and reliable operation of the facility. The Conditions of Certification also assure that the project will neither result in, nor contribute substantially to, any significant direct, indirect, or cumulative adverse environmental impacts.

4. Existing governmental land use restrictions are sufficient to adequately control population density in the area surrounding the facility and may be reasonably expected to ensure public health and safety.

5. The project is subject to Fish and Game Code section 711.4 and the project owner must therefore pay an eight hundred fifty dollar ($850) fee to the California Department of Fish and Game.

6. Construction and operation of the project, as mitigated, will not create any significant adverse environmental impacts. Therefore, the evidence of record also establishes that no feasible alternatives to the project, as described during these proceedings, exist which would reduce or eliminate any significant environmental impacts of the mitigated project.

7. The evidence of record does not establish the existence of any environmentally superior alternative site.

8. The evidence of record establishes that an environmental justice screening analysis was conducted and that the project, as mitigated, will not have a disproportionate impact on low-income or minority populations.

9. The Decision contains a discussion of the public benefits of the project as required by Public Resources Code section 25523(h).

10. The Decision contains measures to ensure that the planned, temporary, or unexpected closure of the project will occur in conformance with applicable laws, ordinances, regulations, and standards.

11. The proceedings leading to this Decision have been conducted in conformity with the applicable provisions of Commission regulations governing the consideration of an Application for Certification and thereby meet the requirements of Public Resources Code sections 21000 et seq. and 25500 et seq.

ORDER

Therefore, the Commission ORDERS the following:

1. The Application for Certification of the Blythe Energy Project, Phase II, as described in this Decision, is hereby approved and a certificate to construct and operate the project is hereby granted.

2. The approval of the Application for Certification is subject to the timely performance of the Conditions of Certification and Compliance Verifications enumerated in the accompanying text and Appendices. The Conditions and Compliance Verifications are integrated with this Decision and are not severable therefrom. While the project owner may delegate the performance of a Condition or Verification, the duty to ensure adequate performance of a Condition or Verification may not be delegated.

3. This Decision is adopted, issued, effective, and final on December 14, 2005.

4. Reconsideration of this Decision is governed by Public Resources Code, section 25530.

5. Judicial review of this Decision is governed by Public Resources Code, section 25531.

6. The Commission hereby adopts the Conditions of Certification, Compliance Verifications, and associated dispute resolution procedures as part of this Decision in order to implement the compliance monitoring program required by Public Resources Code section 25532. All conditions in this Decision take effect immediately upon adoption and apply to all construction and site preparation activities including, but not limited to, ground disturbance, site preparation, and permanent structure construction.

7. The project owner shall provide the Executive Director a check in the amount of eight hundred fifty dollars ($850), payable to the California Department of Fish and Game.

8. The Executive Director of the Commission shall transmit a copy of this Decision and appropriate accompanying documents, including the Department of Fish and Game fee, as provided by Public Resources Code section 25537, California Code of Regulations, title 20, section 1768, and Fish and Game Code section 711.4.

Dated December 14, 2005, at Sacramento, California.

JOSEPH DESMOND Chairman	Art Rosenfeld ARTHUR H. ROSENFELD Commissioner
(Absent) JAMES D. BOYD Commissioner	JOHN L. GEESMAN Commissioner
JACKALYNE PFANNENSTIEL Commissioner	