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DATE: March 12, 2012

TO: Interested Parties

FROM: Mary Dyas, Compliance Project Manager

SUBJECT: BLYTHE ENERGY PROJECT, PHASE II (02-AFC-1C)
Staff Analysis of Proposed Modifications

On October 23, 2009, Caithness Blythe II, LLC (Caithness) filed a petition with the California Energy Commission (Energy Commission) to amend the Energy Commission Decision for the Blythe Energy Project, Phase II (BEP II). Staff prepared an analysis of the proposed changes, and a copy is enclosed for your information and review.

The licensed BEP II project is a 520-megawatt (MW) combined cycle power plant located within the City of Blythe, approximately five miles west of the center of the City, in Riverside County. The project was certified by the Energy Commission in December 2005 and has not begun construction.

The proposed modifications include defining a new point of electrical interconnection via a 2,100 foot-long 500 kilovolt transmission line into the proposed Keim substation; replacement of the Siemens Westinghouse V84.3a turbines, which are no longer available, with fast-start Siemens SGT6-5000F turbines; modification of the combustion turbine and steam turbine enclosure; incorporation of an auxiliary boiler to allow fast start technology; addition of 1,020 sq. ft. of cooling tower; and optimization of the General Arrangement.

Energy Commission staff reviewed the petition, including all supplemental materials, and assessed the impacts of this proposal on environmental quality, public health and safety, and proposes revisions or additions to existing conditions of certification for Air Quality, Hazardous Materials Management, Water Resources, Transmission System Engineering, and Worker Safety. It is staff's opinion that, with the implementation of revised and new conditions, the project will remain in compliance with applicable laws, ordinances, regulations, and standards and that the proposed modifications will not result in a significant adverse direct or cumulative impact to the environment (Title 20, California Code of Regulations, Section 1769).

The amendment petition and staff's analysis has been posted on the Energy Commission's webpage at
http://www.energy.ca.gov/sitingcases/blythe2/compliance/index.html. The Energy Commission's Order will also be posted on the webpage if the petition to amend is approved. Energy Commission staff intends to recommend approval of the petition at

the April 11, 2012**,** Business Meeting of the Energy Commission. If you have comments on the proposed modifications, please submit them to me at the address below prior to April 10, 2012.

Mary Dyas, Compliance Project Manager
California Energy Commission
1516 9th Street, MS-2000
Sacramento, CA 95814

Comments may be submitted by fax to (916) 654-3882, or by e-mail to mdyas@energy.ca.gov. If you have any questions, please contact me at (916) 651-8891.

For further information on how to participate in this proceeding, please contact the Energy Commission Public Adviser's Office, at (916) 654-4489, or toll free in California at (800) 822-6228, or by e-mail at publicadviser@energy.state.ca.us. News media inquiries should be directed to the Energy Commission Media Office at (916) 654-4989, or by e-mail at mediaoffice@energy.state.ca.us.

Enclosure

STAFF ANALYSIS

BLYTHE ENERGY PROJECT
PHASE II

PETITION TO AMEND

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BLYTHE ENERGY PROJECT, PHASE II (02-AFC-1C)
PETITION TO AMEND COMMISSION DECISION
EXECUTIVE SUMMARY

Prepared by Mary Dyas

INTRODUCTION

On October 23, 2009, Caithness Blythe II, LLC (Caithness) filed a petition with the California Energy Commission requesting to modify the Blythe Energy Center, Phase II project (BEP II). A modification to the petition was filed on January 4, 2010. Supplemental water information was filed on February 16, 2010, supplemental Transmission System Engineering (TSE) information was filed on April 23, 2010, supplemental Traffic and Transportation and TSE information was filed, and on October 4, 2011, and supplemental water information was received on March 6, 2012.

The purpose of the Energy Commission's review process is to assess any impacts the proposed modifications would have on environmental quality and public health and safety. The process includes an evaluation of the consistency of the proposed changes with the Energy Commission's Final Decision (Decision), and if the project, as modified, will remain in compliance with applicable laws, ordinances, regulations, and standards (LORS) (Title 20, Calif. Code of Regulations, section 1769).

This Staff Analysis contains the Energy Commission staff's evaluation of the affected technical areas including Air Quality, Hazardous Materials Management, Transmission System Engineering, Water Resources and Worker Safety.

PROJECT LOCATION AND DESCRIPTION

The BEP II is licensed as a nominally rated 520-megawatt (MW) combined-cycle facility with a maximum output of 538 MWs. The project was certified by the Energy Commission on December 14, 2005.

The Project is located within the City of Blythe, approximately five miles west of the center of the City. The BEP II site boundary is located on a 76 acre site immediately adjacent to the operational Blythe Energy Project (BEP I), owned by Blythe Energy, LLC and operated by NextEra Energy Operating Services, LLC.

DESCRIPTION OF PROPOSED MODIFICATIONS

The proposed modifications include the following:

- Define a new point of electrical interconnection via a 2,100 foot-long 500 kilovolt transmission line into the proposed Keim substation;
- Replacement of the Siemens Westinghouse V84.3a turbines, which are no longer available, with fast-start Siemens SGT6-5000F turbines;

- Modification of the combustion turbine and steam turbine enclosure;
- incorporation of an auxiliary boiler to allow fast start technology;
- Increase in size of cooling tower by 1,020 square feet to improve the efficiency and performance of the plant at higher temperatures; and
- Optimization of the General Arrangement.

The General Arrangement of the facility will be modified to optimize the location of the facilities with the Siemens SGT6-5000F turbine generators, larger steam turbine generator and their respective enclosures. These modifications include:

- Relocation of the demineralized water storage tank;
- Creation of two additional parking lots;
- Relocation of the structure for the power control center;
- Relocation of the workshop/ storage area;
- Slight relocation of the general layout of the facility to the east;
- Relocation of the control room building, and
- Relocation of the raw water storage tank.

NECESSITY FOR THE PROPOSED MODIFICATIONS

The primary purpose and need for this amendment is to define the point of electrical interconnection for the BEP II project. The combustion turbines and associated equipment contained in the Decision are obsolete and no longer commercially available. This equipment has been updated and replaced with newer-generation combustion turbines that are more efficient and generate greater capacity with a similar footprint.

The proposed amendments to the BEP II project are intended to make the project a fully dispatchable, high efficiency quick start facility to meet the current and project market demands for Southern California.

STAFF'S ASSESSMENT OF THE PROPOSED PROJECT CHANGES

The technical areas contained in this Staff Analysis indicate recommended staff changes to the existing BEP II Decision and conditions of certification. Staff believes that by requiring the proposed changes to the existing conditions or the addition of new conditions, the potential impacts of the proposed changes would be reduced to less than significant levels. A summary of staff's conclusions reached in each technical area are summarized in the following table. The details of the proposed condition changes can be found under the appropriate technical headings in this Staff Analysis.

Energy Commission technical staff reviewed the petition to amend for potential environmental effects and consistency with applicable LORS. Staff has determined that the technical or environmental areas of Biological Resources, Cultural Resources, Facility design, Geological and Paleontological Resources, Public Health, Noise and Vibration, Traffic and Transportation, Transmission Line Safety and Nuisance, Visual Resources, and Waste Management are not affected by the proposed changes, and no revisions or new conditions of certification are needed to ensure the project remains in compliance with all applicable LORS and existing conditions of certification in the Decision.

Staff has determined that the technical areas of Air Quality, Hazardous Materials Management, Water Resources, Transmission System Engineering, and Worker Safety would be affected by the proposed project changes and have proposed new or revised conditions of certification in order to assure compliance with LORS and/or to reduce potential environmental impacts to a less than significant level.

EXECUTIVE SUMMARY Table 1
Summary of Technical Area Response to Petition

TECHNICAL AREAS REVIEWED	STAFF RESPONSE		
	Technical Area Not Affected	No Significant Environmental Impact*	Process As Amendment**
Air Quality			X
Biological Resources	X		
Cultural Resources	X		
Geological Hazards & Resources		X	
Hazardous Materials Management			X
Facility Design	X		
Land Use	X		
Noise and Vibration	X		
Paleontological Resources	X		
Public Health		X	
Socioeconomics	X		
Traffic and Transportation		X	
Transmission Line Safety & Nuisance	X		
Transmission System Engineering			X
Visual Resources		X	
Waste Management	X		
Water Resources			X
Worker Safety			X

*There is no possibility that the modifications may have a significant effect on the environment and the modification will not result in a change or deletion of a condition adopted by the Energy Commission in the final decision or make changes that would cause the project not to comply with any applicable laws, ordinances, regulations, or standards (LORS) (20 Cal. Code Regs., § 1769 (a)(2)).

** New or revised conditions of certification recommended by staff

STAFF RECOMMENDATIONS AND CONCLUSIONS

Staff concludes that, with the implementation of revised and new conditions of certification, the following required findings mandated by Title 20, section 1769(a)(3) of the California Code of Regulations can be made and will recommend approval of the petition to the Energy Commission:

A. There will be no new or additional unmitigated significant environmental impacts associated with the proposed changes;

B. The facility will remain in compliance with all applicable laws, ordinances, regulations and standards;

C. The changes will be beneficial to the project owner because the fast start modifications proposed will substantially reduce start times and therefore start-up emissions, and the project could support deliveries of capacity, energy and ancillary services.

D. There has been a substantial change in circumstances since the Energy Commission certification justifying the changes.

BLYTHE ENERGY PROJECT, PHASE II (02-AFC-1C)
PETITION TO AMEND ENERGY COMMISSION DECISION
AIR QUALITY

Prepared by Tao Jiang, Ph.D., P.E.

SUMMARY OF CONCLUSIONS

Staff finds that with the adoption of the attached revised and new conditions of certification, the modified Blythe Energy Project II (BEP II) is expected to conform with applicable federal, state and Mojave Desert Air Quality Management District (MDAQMD or District) air quality laws, ordinances, regulations and standards (LORS), and that the modified BEP II project would not result in significant air quality-related impacts.

Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in **AIR QUALITY APPENDIX AIR-1**. The BEP II would emit approximately 0.373 metric tonnes of carbon dioxide (CO_2) per megawatt hour (MTCO2/MWh). The project meets the standard of 0.5 metric tonnes CO_2 -equivalent per megawatt-hour. The project is subject to mandatory reporting requirements and GHG reductions or trading requirements as part of California's GHG cap-and-trade program as these regulations are more fully developed and implemented.

INTRODUCTION

The California Energy Commission (CEC) received an amendment request for the Blythe Energy Project Phase II (BEP II) from Caithness Blythe II, LLC on October 23, 2009. BEP II was originally certified by the CEC on December 14, 2005 (02-AFC-1) as a nominally rated 520-megawatt (MW) combined cycle facility with a maximum output of 538 MWs. This project has not yet begun construction. It would be located within the City of Blythe, approximately five miles west of the center of the City. The BEPII would be located on a 76 acre site immediately adjacent to the operational Blythe Energy Project (BEP I). Caithness proposes to modify the currently permitted combustion turbines by replacing the Siemens Westinghouse V84.3a turbines with Siemens SGT6-5000F turbines which would utilize the Siemens Flex Plant ™ 30 rapid start technology. This modification to the turbine power train system would increase the total output of the facility by less than 50 MWs. As modified, the proposed project's nominal output will increase to 569 MWs, with a maximum output of 587 MWs. The increased flexibility would improve the ability of the facility to integrate intermittent renewable energy resources. The amendment request includes:

- A new point of electrical interconnection to the Keim substation.
- Replacement of the Siemens Westinghouse V84.3a turbines, which are no longer available, with Siemens SGT6-5000F turbines.
- Modification of the combustion turbine and steam turbine enclosure.
- Incorporation of a new auxiliary boiler to allow fast start technology.

- Expansion of the approved cooling tower footprint by 1,020 square feet.
- Optimization of the general arrangement of the facility.

In this analysis, staff evaluated the expected air quality impacts from construction and operation of the modified BEP II. The following major points were evaluated:

- whether the modified BEP II is likely to conform with applicable Federal, State and Mojave Desert Air Quality Management District (MDAQMD) air quality laws, ordinances, regulations and standards (Cal. Code Regs., tit. 20, § 1744(b)); and
- whether the modified BEP II is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards and whether the mitigation proposed for BEP II is adequate to lessen the potential impacts to a level of insignificance (Cal. Code Regs., tit. 20, § 1742(b)).

The analysis addresses criteria pollutants that are managed according to federal or state ambient air quality standards to protect public health. They include ozone, nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), reactive organic compounds (ROCs), and particulate matter less than ten microns in diameter (PM10) and less than 2.5 microns in diameter (PM2.5).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

The federal Clean Air Act requires that any new major stationary sources of air pollution and any major modifications to existing major stationary sources to obtain a construction permit before commencing construction. This process is known as New Source Review (NSR). Its requirements differ depending on the attainment status of the area where the major facility would be located. Prevention of Significant Deterioration (PSD) requirements apply in areas that are in attainment with the national ambient air quality standards. Nonattainment NSR applies in areas where pollutants do not comply with national ambient air quality standards. The entire program, including both PSD and nonattainment NSR, is referred to as the federal NSR program.

Title V of the federal Clean Air Act requires implementation and administration of an operating permit program to ensure that large sources operate in compliance with the requirements included in the Code of Federal Regulations (CFR), Title 40, Part 70 (40 CFR 70). A Title V permit contains all of the requirements specified in different air quality regulations that affect an individual project.

Title IV of the federal Clean Air Act requires implementation of an acid rain permit program (40 CFR 72). These regulations require facilities subject to these requirements to obtain emission allowances for oxides of sulfur (SOx) emissions.

The U.S. Environmental Protection Agency (U.S. EPA) has reviewed and approved the MDAQMD regulations for the Nonattainment NSR, Title V, and Title IV programs. These federal permitting programs have been delegated to the MDAQMD for implementation (District Regulation XII for federal Title V and District Regulation XIII for Nonattainment NSR). The MDAQMD rules and regulations implementing the federal programs are as stringent as the federal regulations.

The federal PSD program (40 CFR 52.21) is implemented by the U.S. EPA, which means that an independent application must be filed with the U.S. EPA in order to secure this federal permit. BEP II originally submitted the PSD application in May 2002, and the U.S. EPA provided a preliminary analysis of compliance in April 2003. BEP II submitted a PSD application for this major amendment to EPA Region IX in December 2009. The District's regulatory calendar includes rule-making to adopt PSD requirements at the local level, although the District indicates that such rule-making will not necessarily occur during 2012.

According to the requirements of the MDAQMD NSR programs, BEP II would be a major new stationary source. BEP II is also subject to the federal New Source Performance Standards (NSPS) contained in 40 CFR 60. Enforcement of NSPS has been delegated to the MDAQMD (District Regulation IX). The proposed combined cycle power plant must comply with the requirements of NSPS Subparts Da and GG (for the duct burners and stationary gas turbines, respectively). The federal NSPS allowable emissions concentration for nitrogen oxides (NOx) is 75 parts per million volume dry (ppmvd) at 15% oxygen (O_2), and the NSPS requirement for SO_2 emissions concentration is 150 ppm at 15% O_2.

STATE

California State Health and Safety Code, Section 41700, requires that: "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property."

LOCAL

As part of the Energy Commission's licensing process, the MDAQMD released a Preliminary Determination of Compliance (PDOC) on March 15, 2010 (MDAQMD 2010a) and a Final Determination of Compliance (FDOC) on August 10, 2010 (MDAQMD 2010b) for the modified BEP II. The FDOC incorporates changes made in response to the comments and evaluates whether and under what conditions the proposed project will comply with the applicable rules and regulations. The review by the MDAQMD for the FDOC was conducted in a manner that is equivalent to that for other permits to construct and independent of the federal PSD program. The Energy Commission staff coordinates its analysis with the preparation of FDOC. Provided successful completion of the Energy Commission's licensing process and incorporation of the District's conditions into the decision granted by the Energy Commission, the

Determination of Compliance serves as an equivalent to an Authority to Construct (ATC). A Permit to Operate (PTO) would be issued by the District provided the construction is in compliance with the conditions of the Determination of Compliance and the Energy Commission decision.

The project is subject to the following MDAQMD rules and regulations summarized below:

Regulation II – Permits

Rule 221 – Federal Operating Permit Requirements

Requires submittal of an application for a federal operating permit within twelve months of commencing operation.

Regulation IV – Prohibitions

Rule 401 – Visible Emissions

This rule contains general requirements limiting visible emissions to no darker than Ringelmann No. 1 (20 percent opacity) for periods greater than three minutes in any hour.

Rule 402 – Nuisance

Prohibits any emissions “which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such person or public or which cause or have a natural tendency to cause injury or damage to business or property.”

Rule 403 – Fugitive Dust

Regulates operations that may cause fugitive dust emissions into the atmosphere. Emissions of fugitive dust from transport, handling, construction or storage activities shall not remain visible in the atmosphere beyond the property line of the emission source, or exceed 100 micrograms per cubic meter when determined as the difference between upwind and downwind samples collected on high volume samplers at the property line for a minimum of five hours. These limits are not applicable when the wind speed instantaneously exceeds 40 kilometers (25 miles) per hour, or when the average wind speed is greater than 24 kilometers (15 miles) per hour. The average wind speed determination shall be on a 15 minute average at the nearest official air-monitoring station or by wind instrument located at the site being checked.

Rule 404 – Particulate Matter – Concentration

Specifies standards of emissions for particulate matter concentrations.

Rule 405 – Solid Particulate Matter - Weight

Limits particulate matter emissions from fuel combustion on a mass per unit combusted basis.

Rule 406 – Specific Contaminants

Limits the emissions of sulfur compounds to no greater than 500 parts per million by volume (ppmv), and a number of other contaminants (such as bromine, hydrogen chloride and fluorine) to specific ppmv levels.

Rule 408 – Circumvention

Prohibits hidden or secondary rule violations.

Rule 409 – Combustion Contaminants

Limits discharging of combustion contaminants (PM10) to no greater than 0.1 grains per dry standard cubic foot (gr/dscf).

Rule 430 – Breakdown Provisions

Requires reporting of breakdowns and excess emissions.

Rule 431 – Sulfur Content Of Fuels

Limits sulfur content of gaseous fuel to 800 ppm, calculated as hydrogen sulfide at standard conditions, and liquid or solid fuel to 0.5 percent by weight.

Rule 475 – Electric Power Generating Equipment

Limits the NOx emissions of any electric power generating equipment to no more than 80 ppm if using gaseous fuel, 160 ppm if using liquid fuel and 225 ppm if using solid fuel.

Regulation IX – Standards For Performance For New Stationary Sources

Adopts the requirements of the federal NSPS (40 CFR 60) by reference. The federal NSPS requirements for stationary gas turbines and duct burners are described with other federal requirements, above.

Regulation XII – Federal Operating Permits

Establishes administrative requirements for obtaining a federal operating permit (federal Clean Air Act Title V) and an acid rain permit (Title IV) by the appropriate dates.

Regulation XIII – New Source Review

Rule 1300 – General

Ensures that New Source Review (NSR) requirements apply to all projects.

Rule 1302 – Procedures, New Source Review

Provides administrative procedures for the processing of applications for permits to construct and operate new and modified stationary sources.

Rule 1302(C)(3)(b), Determination of Offsets, states that the applicant shall provide an offset package which contains evidence of offsets eligible for use pursuant to the provisions of Rule 1305.

Rule 1302(C)(3)(b)(iii) states that the District must determine that the offsets are real, enforceable, surplus, permanent and quantifiable and that permit modifications required pursuant to Rule 1305 or Regulation XIV have been made. The District would approve the use of the offsets subject to the approval of California Air Resources Board (ARB) and U.S. EPA during a 30-day public comment period. The District may only issue an ATC after the increase in emissions for each nonattainment pollutant has been properly offset.

Rule 1302(D)(5)(b)(iii) requires that the applicant certify in writing that all facilities which are under the common control of the applicant in the State of California, are in compliance with all applicable emissions limitations and standards under the federal Clean Air Act.

Rule 1303 – Requirements, New Source Review

Provides specific requirements for new or modified stationary sources including Best Available Control Technology (BACT) and offsets. A modification of a major source must apply BACT for each nonattainment air pollutant for which the potential to emit is greater than 25 pounds per day or 25 tons per year. Offsets must be provided for all pollutants that exceed the specified trigger levels.

Rule 1305 – Emissions Offsets

Provides the procedures and formulas for quantifying and determining the eligibility of emission reduction credits (ERCs) available for use as offsets in accordance with Rule 1303.

Rule 1305(B)(5) allows for the use of interbasin offsets from upwind air districts that are outside the Mojave Desert Air Basin. Rule 1305(B)(6) allows for the use of interpollutant offset trading as long as there is technical justification for such a trade and the combined emissions increase from the proposed project and the reductions from the interpollutant offsets do not cause or contribute to a violation of an ambient air quality standard.

New emissions of NOx, ROC and PM10 from BEP II will be offset because BEP II would emit these nonattainment pollutants (or precursors) in quantities greater than the offset applicability thresholds in Rule 1303(B). The District does not consider ammonia to be a precursor to any regulated pollutant [Rule 1301(VV)].

Rule 1306 - Electric Energy Generating Facilities

This rule includes the additional administrative requirements for projects that are required to obtain licensing from the Energy Commission and specifies that a determination of compliance would be prepared by the District. The FDOC confers the same rights and privileges as a New Source Review permit or ATC(s) only when the Energy Commission decision includes all conditions contained in the FDOC [Rule 1306(E)(3)(b)].

SETTING

METEOROLOGICAL CONDITIONS

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

The City of Blythe is located near the border of the Mojave Desert and the Sonoran Desert in the Lower Colorado Valley. Hot, dry summers and mild winters with scant precipitation define the climate. The semi-permanent Pacific High over the eastern Pacific Ocean during the summer months blocks low pressure systems from passing through the area. This results in hot summers, with average daily maximum temperatures during the summer months over 106 ºF. During the winter, the area does not often experience frost. Daily maximum temperatures during the winter months average around 68 ºF, with average wintertime low temperatures being around 42 ºF (WRCC 2011).

During the winter months, the Pacific High weakens and migrates to the south, allowing Pacific storms into California. In addition, the area receives some moisture during the summer monsoon season from the wind flowing up the Colorado River Valley from the Gulf of California. However, due to the rain shadow effect of the mountainous terrain west and south of the Blythe region, the average annual rainfall in the area is only 3.6 inches.

Analysis of the local wind rose diagrams (a graph showing the average wind speed and direction at the location) provided by the applicant in the Amendment indicate that the surface winds in the area are primarily from the south (southeast through southwest), with a secondary component from the north-northwest. (BEP II 2009, Figures 5.2B-6 to 5.2B-10). During the summer months (April through September), winds are predominately from the south, while during the winter months winds are predominately from the north and northwest. The winds are calm approximately 16.4 percent of the time annually and 10.5 percent of the time during the summer months.

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

Because lower mixing heights generally occur during the winter, along with lower mean wind speeds and less vertical mixing, dispersion occurs less rapidly.

EXISTING AIR QUALITY

The project would be located in the Riverside County portion of the Mojave Desert Air Basin (MDAB) and would be under the jurisdiction of the MDAQMD. The U.S. EPA and ARB each designate the status of local air quality through a comparison with the ambient air quality standards (AAQS). The state ambient air quality standards (CAAQS), established by ARB, are typically more restrictive than the federal or national ambient air quality standards (NAAQS), which are established by the U.S. EPA. The state and federal ambient air quality standards are listed in **AIR QUALITY Table 1**. As indicated in this table, the averaging times for the various standards (the duration over which they are measured) range from hourly to annually. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per volume of air, in milligrams or micrograms of pollutant per cubic meter of air (mg/m^3 and $\mu g/m^3$).

The Riverside County portion of the MDAB is designated as non-attainment for the state ozone and PM10 standards. This area is designated as attainment or unclassified for all federal criteria pollutant ambient air quality standards and the state CO, NO_2, SO_2, and PM2.5 standards. **AIR QUALITY Table 2** summarizes the project site area's attainment status for various applicable state and federal standards.

LOCAL AIR QUALITY DATA

Ambient air quality monitoring data for ozone, PM10, PM2.5, CO, NO_2, and SO_2, compared to most restrictive applicable standards for the years between 2004 through 2009/2010 at the most representative monitoring stations for each pollutant are shown in **AIR QUALITY Table 3**. Data in **bold** represents the highest historical value and the background value used in the staff assessment of project impacts. Ozone data are from the Blythe-445 West Murphy Street monitoring station, located 5 ½ miles east of the facility location; PM10, PM2.5, NO_2, and CO data are from the Palm Springs-Fire Station monitoring station, located 107 miles west of the facility location and SO_2 data are from the Victorville-14306 Park Avenue monitoring station, located 163 miles west northwest of the facility location. These monitoring data can be expected to represent air quality levels at the project site or are higher in value than what would be monitored at the project site, meaning that the values conservatively represent air quality conditions at the site.

AIR QUALITY Table 1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone ($O3$)	8 Hour	0.075 ppm (147 µg/m^3)[a]	0.070 ppm (137 µg/m^3)
	1 Hour	—	0.09 ppm (180 µg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO2)	Annual	53 ppb (100 µg/m^3)	0.030 ppm (57 µg/m^3)
	1 Hour	100 ppb (188 µg/m^3)[b]	0.18 ppm (339 µg/m^3)
Sulfur Dioxide (SO2)	24 Hour	—	0.04 ppm (105 µg/m^3)
	3 Hour	0.5 ppm (1300 µg/m^3)	—
	1 Hour	75 ppb (196 µg/m^3)[c]	0.25 ppm (655 µg/m^3)
Respirable Particulate Matter (PM10)	Annual	—	20 µg/m^3
	24 Hour	150 µg/m^3	50 µg/m^3
Fine Particulate Matter (PM2.5)	Annual	15 µg/m^3	12 µg/m^3
	24 Hour	35 µg/m^3 [b]	—
Sulfates (SO4)	24 Hour	—	25 µg/m^3
Lead	30 Day Average	—	1.5 µg/m^3
	Rolling 3-Month Average	1.5 µg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42 µg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.01 ppm (26 µg/m^3)
Visibility Reducing Particulates	8 Hour	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

Note: [a] Fourth- highest maximum 8 – hour concentration, averaged over 3 years.

[b] 98th percentile of daily maximum value, averaged over 3 years.

[c] 99th percentile of daily maximum value, averaged over 3 years.

AIR QUALITY Table 2
Federal and State Attainment Status
Project Site Area within Riverside County

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

Source: ARB 2011a, U.S.EPA 2011a.

[a] Unclassified or Attainment status for the site area only, not the entire MDAB. The US EPA intends to designate this portion of Riverside County as non-attainment of the federal 8-hour ozone standard in the spring of 2012.

[b] On January 20, 2012 US EPA designated all of California as "unclassifiable/attainment" for their short-term NO_2 standard.

Ozone

In the presence of ultraviolet radiation in sunlight, both NOx and ROC go through a number of complex chemical reactions to form ozone. Ozone formation is highest in the spring and summer, when abundant sunshine and high temperatures are available to trigger the necessary photochemical reactions, while concentrations are lowest in the winter. **AIR QUALITY Table 3** summarizes the most-representative ambient ozone data collected from the Blythe-445 West Murphy Street monitoring station.

AIR QUALITY Table 3
Criteria Pollutant Summary
Maximum Ambient Concentrations (ppm or µg/m^3)

Pollutant	Averaging Period	Units	2004	2005	2006	2007	2008	2009	2010
Ozone	1 hour	ppm	0.078	0.084	0.078	0.092	0.074	0.072	0.072
Ozone	8 hours	ppm	0.067	0.072	0.059	0.075	0.071	0.066	0.066
PM10 [a]	24 hours	µg/m^3	79	66	73	83	75	140	37
PM10 [a]	Annual	µg/m^3	26.4	25.9	24.5	30.5	23.2	--	--
PM2.5 [a]	24 hours	µg/m^3	23.3	25	15.9	20.5	17.1	14.6	12.6
PM2.5 [a]	Annual	µg/m^3	9.0	8.4	7.7	8.7	7.2	6.6	5.9
CO	1 hour	ppm	2.1	2.1	2.3	1.5	1.3	2.3	
CO	8 hours	ppm	0.8	0.8	0.85	0.79	0.54	0.67	0.56
NO_2	1 hour	ppm	0.066	0.059	0.093	0.063	0.049	0.048	0.046
NO_2	Annual	ppm	0.013	0.012	0.01	0.01	0.009	0.008	0.009
SO_2	1 hour	ppm	0.011	0.012	0.018	0.009	0.006	0.028	
SO_2	3 hour	ppm	0.007	0.008	0.012	0.006	0.005	0.006	
SO_2	24 hours	ppm	0.003	0.003	0.005	0.005	0.002	0.005	0.007
SO_2	Annual	ppm	0.0013	0.0013	0.0015	0.0013	0.0011	0.000	0.000

Source: ARB 2011b, U.S.EPA 2011b

[a] Exceptional PM concentration events, such as those caused by wind storms are not shown where excluded by U.S.EPA; however, some exceptional events may still be included in the data presented.

Respirable Particulate Matter

Respirable particulate matter (PM10) can be emitted directly by a range of sources, including combustion of any fossil fuel, and it can be formed many miles downwind when various precursor pollutants interact in the atmosphere. However, at the site's proposed location, the ambient PM10 emissions are dominated by fugitive PM10 instead of combustion or transport sector PM10. Therefore the PM10 reduction achieved from the fugitive dust mitigation, such as road paving used in this project, will be suitable for the PM10 mitigation from the project. It is worth noting that the MDAQMD supports the use of road paving PM10 reductions to offset the PM10 impacts from natural gas turbines (MDAQMD 1995 and 2010b).

Given the right meteorological conditions, gaseous emissions of pollutants like NOx, SOx, and ROC from combustion sources, and ammonia from agriculture, waste-water treatment, or NOx control equipment, can form particulate matter composed of nitrates (NO_3^-), sulfates (SO_4^{2-}), and organics. These pollutants are known as secondary particulates, because they are not directly emitted, but are formed through a set of complex chemical reactions in the atmosphere. Particulate nitrate can be formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. In urbanized areas, the nitrate ion concentrations can be a significant portion of the total PM10. Nitrate ions are only one component of particulate nitrate, which typically takes the form of ammonium nitrate or sodium nitrate.

Secondary particulates are probably a minor fraction of the overall PM10 concentrations in the project area because there are few major sources of precursors. In the desert, windblown dust contributes to elevated PM10 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.

AIR QUALITY Table 3 shows that the project site area within Mojave Desert Air Basin experiences ongoing violations of the state 24-hour PM10 standard except in 2010. The less-stringent federal standards have not recently been violated by ambient PM10 concentrations. Historic violations of federal PM10 standards in the Mojave Desert Planning Area (San Bernardino County) led the MDAQMD to prepare a PM10 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).

Fine Particulate Matter

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

The entire MDAB is classified as unclassified/attainment for the federal PM2.5 standard and, in the project area, is designated unclassified for the state PM2.5 standards. This divergence in the PM10 and PM2.5 concentration levels and attainment status indicates that a substantial fraction of the ambient particulate matter levels are larger particles that are most likely due to localized fugitive dust sources, such as vehicle travel on unpaved roads, agricultural operations, or wind-blown dust[1].

Concentrations of PM10 and PM2.5 in the Mojave Desert are weakly seasonal, with higher PM2.5 concentrations normally occurring in the winter. High PM10 concentrations from windblown dust can occur during any time of the year. Managing PM2.5 concentrations will require the air district to identify controllable sources and develop feasible source management strategies. Because PM10 includes PM2.5 as a subset and reactive precursors that lead to ozone can also lead to PM2.5, the established strategies for controlling PM10 and ozone precursors (including existing programs for combustion sources) also presently help to reduce PM2.5 concentrations.

1 Fugitive dust, unlike combustion source particulate and secondary particulate, is composed of a much higher fraction of larger particles than smaller particles, so the PM2.5 fraction of fugitive dust is much smaller than the PM10 fraction. Therefore, when PM10 ambient concentrations are significantly higher than PM2.5 ambient concentrations this tends to indicate that a large proportion of the PM10 are from fugitive dust emission sources, rather than from combustion particulate or secondary particulate emission sources.

PROJECT DESCRIPTION AND EMISSIONS

This section describes the project design, project emissions, and air pollutant control devices as described in the BEP II AFC Amendment (BEP II 2009).

CONSTRUCTION PHASE

Project Site

BEP II would be located adjacent to BEP I, a power plant of substantially similar design. BEP I was certified by the Energy Commission on March 21, 2001, and began commercial operation on December 29, 2003. BEP II project construction would last for a total of 16 months (not including startup and commissioning). Construction equipment use estimates are based on a construction schedule of 6 days per week, 10 hours per day (BEP II 2009, Appendix 5.2-E).

During construction, approximately a total area of 76 acres would be disturbed due to construction activities for the power plant and ancillary facilities. All the construction lay down and parking areas, which would be used for materials storage and craft labor parking, are within the already enclosed and graded site and will be identified under and pursuant to Condition Land-2.

Linear Facilities

BEP II requires no offsite linear facilities and would be interconnecting to the Keim substation and existing natural gas pipelines on the BEP I site. The BEP II point of delivery to the California Independent System Operator (CAISO) will be the Southern California Edison (SCE) Colorado River Substation (CRS) currently under construction. The approximate 8.0 miles of transmission line from Keim substation to the new CRS is part of the proposed Desert Southwest Transmission Project (DSWTP), which is not within the scope of this analysis.

Project Construction Emissions

During the construction period, emissions will be generated from the exhaust of the heavy equipment and fugitive dust from earthwork and activity on unpaved surfaces. Heavy equipment would include loaders and haul trucks to deliver construction materials, excavators and backhoes for earthwork, graders, cranes, lifts, construction vehicles and smaller equipment such as welders, generators, and air compressors. Fugitive dust emissions would occur due to activity on the exposed surfaces at the site, especially those portions that are unpaved.

AIR QUALITY Table 4 summarizes the different levels of criteria pollutants that are estimated to be generated from the 16-month construction phase for BEP II. The construction equipment and fugitive dust emissions were based on emission factors and load factors published by the U.S. EPA, Sacramento County Air Pollution Control District and South Coast Air Quality Management District. The equipment emission rates assume use of California-required low-sulfur diesel fuel and engines that comply with U.S. EPA and California ARB off-road equipment emission standards. The applicant provided the estimated number of operational hours for each piece of equipment throughout project construction outlined in the AFC Amendment (BEP II 2009, Appendix 5.2-E). For equipment, the mitigation measures identified by the applicant include limiting engine idling time, shutting down equipment when not in use, and conducting routine preventative maintenance to the manufacturer's specifications. For fugitive dust, emission reductions would be achieved with dust suppression measures specified by the applicant along with those specified in the Energy Commission's Conditions of Certification. The emissions in **AIR QUALITY Table 4** account for the emission control measures the applicant proposes to incorporate (BEP II 2009, Appendix 5.2 E).

AIR QUALITY Table 4
BEP II, Estimated Emissions from Construction

	NOx		PM10		PM2.5		CO		SOx		ROC	
Equipment	lb/hr [(a)]	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Equipment and Vehicle Exhaust	14.7	19.43	0.75	0.98	0.74	0.98	6.2	8.18	0.02	0.04	2.05	2.7
Construction Fugitive Dust	0	0	7.59	2.33	1.59	0.45	0	0	0	0	0	0
Total	14.7	19.43	8.3	3.31	2.33	1.4	6.2	8.18	0.02	0.04	2.05	2.7

Source: BEP II 2009, Appendix 5.2 E.

(a) Hourly emission estimates are based on applicant's estimate of total emissions by day divided by 10 hours per day of activity as per applicant's equipment use estimates.

OPERATIONAL PHASE

Equipment Description

The new nominally-rated 569 MW combined cycle power plant would include the following:

- Two Siemens Westinghouse SGT6-5000F combustion turbine generators (CTGs) 2019.6 million British thermal units per hour (MMBtu/hr), each generating approximately 190 MW. Each CTG includes dry low-NOx combustors for NOx reduction. Each CTG would be coupled to a heat recovery steam generator (HRSG) at an estimated maximum fuel input capacity of 221.6 MMBtu/hr with supplemental duct burners and an integral selective catalytic reduction (SCR) system to control NOx emissions.
- An auxiliary boiler with a fuel input capacity of 60 MMBtu/hr to improve unit startup efficiency.
- A single condensing steam turbine.
- An 11-cell wet mechanical draft cooling tower equipped with high efficiency drift eliminators.
- Diesel-fueled emergency fire pump engine (300 hp).

Equipment Operation

Fuel for the BEP II combined cycle power plant will be exclusively pipeline-quality natural gas. BEP II is designed to provide a nominally rated output of 569 MW while meeting all applicable emission limitations. Natural gas would be delivered to the site by interconnection to the existing natural gas pipeline for the BEPI site, located immediately adjacent to the proposed BEP II project site.

Emission Controls

Both of the CTGs will be equipped with dry low-NOx (DLN) combustors and SCR and will limit their time in higher-emitting start-up mode using Siemens' Flex-start capability. As a reagent, the SCR system relies on use of aqueous ammonia vapor injected to the turbine exhaust stream. With this design, the applicant proposed to limit NOx to 2.0 ppmvd at 15% O_2 (based on a 1-hour average). The applicant proposes to limit stack emissions of ammonia (known as ammonia slip) to 5 ppmvd at 15% O_2 (3-hour average), except during periods of start-up, shutdown, and malfunction.

Through the use of advanced combustion controls, the applicant proposes to achieve CO concentrations of 3 ppmvd averaged over one or three hours with and without duct burners. A more stringent 2.0 ppmvd CO limit (based on a 1-hour average, with and without duct burning) is required by the FDOC, except during periods of startup, shutdown and malfunction. The applicant also proposes a ROC emission limit of 1 ppmvd with no duct burner and 2 ppmvd with duct burner, averaged over one hour. The FDOC determined that this limit is acceptable as ROC and trace organic BACT for the BEPII combined cycle gas turbines, achieved with combustion controls.

A continuous emission monitor (CEM) will be installed on each CTG/HRSG exhaust stack to monitor NOx, CO, and oxygen concentrations to assure adherence with the emission limits. The CEM systems will generate reports of emissions data in accordance with permit requirements and will send alarm signals to the control room when the level of emissions approaches or exceeds pre-selected limits.

The exclusive use of pipeline-quality natural gas, a relatively clean-burning fuel, will limit emissions of PM10, PM2.5 and SO_2. Natural gas contains very little noncombustible gas or solid residues and a small amount of reduced sulfur compounds including mercaptan, thus resulting in relatively low emissions of PM10 and SO_2. The applicant proposes the sole use of natural gas with a sulfur content not greater than 0.5 grains/100 dscf short term (24 hours or less) and 0.25 grains/100 dscf on an annual average basis as fuel as PM10 BACT. The District determined that this is acceptable as SOx BACT for the BEP II combined cycle gas turbines and auxiliary boiler.

The BEP II cooling tower will be equipped with mist eliminators guaranteed by the manufacturer to limit drift to 0.0005 percent. The applicant proposes a total dissolved solids (TDS) limit of 5,050 ppmv, and a maximum water circulation rate of 108,000 gpm for the cooling tower. To provide a reasonable worst-case assessment of impacts to ambient air quality, staff assumes that 100 percent of the TDS would be emitted to the ambient air as PM10 (U.S. EPA AP-42 Section 13.4).

Project Operating Emissions

Operating the major project components will cause emissions of criteria air pollutants. The assumptions used in estimating the emissions here include:

- manufacturer's guaranteed emission rates;
- the facility operating for approximately 8,510 hours per year;
- a range of load conditions (60 percent to 100 percent, with or without duct firing) and a range of ambient temperatures (20°F, 60°F, 95°F, and 108°F);
- typical operating scenarios for estimating daily and annual emissions based on a worst-case day with one warm/hot start, one cold start and two shutdowns, 1 hour of operation with no duct burners and 17 hours of operation with duct burners (except for the worst-case PM emissions with 19.5 hours of operation with duct burners and 4.5 hours of operation without duct burners) and a worst-case year with 300 warm/hot starts, 10 cold starts, 310 shutdowns, 5,820 hours of operation with no duct burner, and 2,200 hours of operation with duct burner, based on calculations from the FDOC;
- operating the diesel-fueled fire water pump engine for 50 hours per year for readiness testing.

During normal operation, the plant will start up and shut down periodically. The amount of time that units are shut down defines whether the subsequent startup is a cold, warm or hot start. The applicant notes that different startup times for each combustion turbine depend on the sequence of the startup; the turbine started first requires slightly more time to come up to steady-state operating conditions. The expected emission rates during startup and shutdown events are summarized in **AIR QUALITY Table 5**. Other sources will have the same emissions rate during startups, shutdowns and routine operation and are not shown in **AIR QUALITY TABLE 5**.

AIR QUALITY Table 5
BEP II, Combustion Turbine Startup and Shutdown Emissions (lb/hr)

Operational Mode (Each turbine)	NOx	PM10/PM2.5	CO	SOx	ROC
	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Cold Startup (3 hrs)	40.3	6.0	46.8	3.0	16.9
Warm/Hot Startup (1 hr)	81.9	6.0	58.5	3.0	46.8
Shutdown (1 hr)	29.7	7.5	25.3	3.3	20.9

Source: BEP II 2009, Table 5.2-5; MDAQMD 2010b.

Emissions during non-startup or shutdown conditions would be fully controlled because all combustion and post-combustion control systems would be operating. The anticipated hourly emissions are shown in **AIR QUALITY Table 6**.

AIR QUALITY Table 6
BEP II, Hourly Operational Emissions (lb/hr)

Operational Source	NOx (lb/hr)	PM10/PM2.5 (lb/hr)	CO (lb/hr)	SO_2 (lb/hr)	ROC (lb/hr)
Each CTG/HRSG	17.9	7.5	10.9	3.3	6.3
Auxiliary Boiler	0.6	0.3	1.9	0.1	0.1
Emergency Fire Pump Engine	1.7	0.1	0.6	0.0	0.1
Cooling Tower	--	1.36	--	--	--

Source: BEP II 2009, Table 5.2-4 and 5.2-7; MDAQMD 2010b.

In order to determine maximum emissions over the course of one typical day or year, it is necessary to examine various startup scenarios in combination with shutdown and normal operation. Assumptions must be made about the frequency of startups or shutdowns although it is impossible to exactly define how often startups would occur. Staff does not propose to place a limit on the number or type of startups each day or year, but the daily and annual emission limits would serve as a practical constraint. The assumptions leading to the estimates of daily and annual emissions are illustrated above. It is assumed that both CTGs could startup simultaneously. **AIR QUALITY Table 7** summarizes the estimated maximum daily emissions from the project.

AIR QUALITY Table 7
BEP II, Maximum Daily Operational Emissions (lb/day)

Operational Source	NO_x (lb/day)	PM10/PM2.5 (lb/day)	CO (lb/day)	SO_2 (lb/day)	ROC (lb/day)
Each CTG/HRSG	582.7	172.5	444.7	77.7	249.3
Auxiliary Boiler	0.6	0.3	1.9	0.1	0.1
Emergency Fire Pump Engine	1.7	0.1	0.6	0.0	0.1
Cooling Tower	--	32.64	--	--	--
Facility Total	1,168	378	892	154	499

Source: BEP II 2009, Table 5.2-6, 5.2-7, and 5.2-8; MDAQMD 2010b.

AIR QUALITY Table 8 summarizes the maximum annual emissions from the project based on the assumptions provided above.

AIR QUALITY Table 8
BEP II, Estimated Annual Operational Emissions (tons per year, tpy)

Operational Source	NO_x (tpy)	PM10/PM2.5 (tpy)	CO (tpy)	SO_2 (tpy)	ROC (tpy)
Each CTG/HRSG	84.3	27.9	54.2	6.6	25.9
Auxiliary Boiler	0.7	0.3	2.3	0.2	0.1
Emergency Fire Pump Engine	0.0	0.0	0.0	0.0	0.0
Cooling Tower	--	5.98	--	--	--
Facility Total	169.4	60.9	110.7	13.3	51.9

Source: BEP II 2009, Table 5.2-6, 5.2-7, and 5.2-8; MDAQMD 2010b.

Ammonia Emissions

Due to the large combustion turbines used in this project and the need to control NOx emissions, significant amounts of aqueous 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. The applicant proposed maximum emissions of ammonia to be approximately 32 pounds per hour per CTG/HRSG (BEP II 2009, Appendix 5.2-A). However, the district approved a lower amount, equivalent to an ammonia limit of 5 ppmvd over three hours (MDAQMD 2010b).

INITIAL COMMISSIONING

The initial commissioning of a power plant refers to the time frame between the completion of the construction and the reliable production of electricity for sale on the market. Normally, during the initial commissioning the post-combustion control systems (the catalyst systems) may not be fully installed or operational. Different turbine manufacturers specify different commissioning activities and durations. The applicant identified the series of tests that would result in greater-than-routine emissions as each unit is commissioned. The sequence of commissioning would be as follows: 1) Combustion turbine first fire, combustion turbine 0 to 35 percent load testing, and HRSG boil out (60 hours); 2) Steam blow and combustion turbine 0 to 50 percent load operation (72 hours); 3) SCR catalyst and CO catalyst installation; 4) Emissions control tuning, base load/bypass[2]/peak tuning/testing, commissioning duct burners, CEMS 7-drift[3]/Emissions & Relative Accuracy Test Audits (RATA) testing, and performance testing and certification (570 to 634 hours). The duration of all these tests is estimated to be 85 days total.

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. The emissions anticipated by the applicant for the commissioning period are summarized in **AIR QUALITY Table 9**.

[2] The term “bypass” as used here refers to the use of the auxiliary boiler to maintain heat in the steam turbine and heat recovery steam generator piping. There is no gas turbine bypass of the SCR.

[3] The 7-day drift test is a federal requirement in Code of Federal Regulations Part 75, Acid Rain program.

AIR QUALITY Table 9
BEP II, Proposed NOx and CO Commissioning Emissions

Commissioning Sources	Pollutant, Averaging Time	Maximum Emissions
Each CTG/HRSG	NOx, hourly	193.5 lb/hr
	NOx, total	25.5 tons
	CO, hourly	2713 lb/hr
	CO, total	203.5 tons

Source: BEP II 2009, Table 5.2-19; MDAQMD 2010b.

Staff anticipates that the applicant would minimize commissioning emissions by limiting the time of each commissioning activity to the shortest duration feasible, consistent with manufacturer's recommendations, because emissions occurring during commissioning would accrue towards the annual limitations imposed by the MDAQMD and commissioning activities must precede commercial operation and revenue generation.

PROJECT IMPACTS

MODELING APPROACH

Air dispersion modeling provides a means of predicting the location and magnitude of the air contaminant impacts of a new emissions source at ground level. The models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for representative ambient meteorological conditions. Model results are often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$). They are an estimate of the concentration of the pollutant emitted by the project that will occur at ground level.

Inputs for the modeling analysis include stack information (exhaust flow rate, temperature, and stack dimensions), specific turbine emission data and meteorological data, such as wind speed, atmospheric conditions, and site elevation. For this project, the meteorological data used as inputs to the model included hourly wind speeds and directions measured by the Automated Surface Observing Systems (ASOS) at Blythe Airport for the years 2002 through 2006. Upper air data from Tucson, Arizona, was also used with the local surface data to form the dispersion model meteorology input file. Tucson is the closest representative National Weather Service radiosonde station that, when combined with the proposed surface dataset, meets the USEPA required data recovery rate of 90 percent.

The applicant used a regulatory-guideline model approved by the U.S. EPA (AERMOD Version 09292) to estimate the impacts of project-related NOx, PM10, PM2.5, CO and SOx emissions. A description of the modeling analysis for operational and commissioning activities is provided in AFC Section 5.2.5.8, and for construction activities is provided in AFC Appendix 5.2-E (BEP II 2009).

NOx emissions from internal combustion sources are primarily in the form of nitric oxide (NO) rather than nitric dioxide (NO_2). Nitric oxide converts into NO_2 in the atmosphere, primarily through the reaction with ambient ozone. The applicant used the U.S.EPA ambient ratio method (ARM) default multiplier of 0.75 as the worst-case downwind annual NO_2/NOx ratio for the determination of the annual NO_2 concentration for construction and operation. In their modeling analysis for short-term 1-hour NO_2 impacts, the applicant originally assumed 100 percent conversion of NOx emissions to NO_2 concentrations. Although this modeling method is very conservative and over predicts actual worst case 1-hour NO_2 concentrations, the modeled impacts are still well below the state 1-hour standard.

For the federal short-term NO_2 standard, the U.S. EPA implemented a new 1-hour NO_2 standard of 0.1 ppm, which became effective on April 12, 2010. The new standard is expressed as a 3-year average of the 98^{th} percentile of the *daily maximum* 1-hour concentration (i.e., the 8^{th} highest of daily highest 1-hour concentrations). The applicant has also provided a modeling analysis to show compliance with the new federal 1-hour NO_2 standard (BEP II 2010a and 2010b). This modeling analysis, also using the AERMOD dispersion model, includes the use of the NOx Ozone Limiting Method (NOx_OLM) modeling option and used a post-processor developed by the applicant's consultant to also add in the corresponding hourly NO_2 background data and determine the 98^{th} percentile of daily maximums (eighth highest) for each modeled receptor location. The NOx_OLM option considers that the emissions of NOx are initially primarily in the form of NO that over time oxidizes, primarily through a reaction with ozone, to NO_2. The initial NO_2/NOx ratio was set at the default value of 0.1 and the conversion of the rest of the NOx to NO_2 is assumed to be limited by the corresponding hourly ambient ozone concentration. For this modeling analysis the applicant obtained hourly monitored ozone concentration data, concurrent with the 2002 to 2006 meteorological data, from the Blythe monitoring station and filled missing data by linear interpolation or using available Joshua Tree Monument and Victorville monitoring station data. Since the hourly NO_2 data are not measured at the Blythe monitoring station, data from the nearest representative NO_2 station, Victorville, were used.

The applicant's modeled impacts were added to the available highest ambient background concentrations measured during 2004 to 2010 at the nearest monitoring station (see **AIR QUALITY Table 3** above), except for the federal 1-hour NO_2 analysis where concurrent hourly background NO_2 during 2002 to 2004 were used. Staff then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or contribute to an existing violation.

CONSTRUCTION IMPACTS

The applicant provided staff with a modeling analysis of the impacts caused by the construction-related emissions. The modeling incorporates the applicant's construction mitigation measures. Staff reviewed the applicant's modeling analysis and supporting information and concludes that it is adequate.

The results of the construction impacts analyses are presented in **AIR QUALITY Table 10**. The values in **bold** represent values that equal or exceed the relevant air quality standard. Even without any project-related impacts, existing background conditions for PM10 exceed the state standard.

AIR QUALITY Table 10
BEP II, Ambient Air Quality Impacts from Construction ($\mu g/m^3$)

Pollutants	Avg. Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Standard ($\mu g/m^3$)	Percent of Standard
NO_2[a]	1-hr.	62.8	92.1	155	339	46
	Annual	1.65	17.1	19	57	33
CO	1-hr	26.4	2,645	2,671	23,000	12
	8-hr	10.1	744	754	10,000	8
PM10	24-hr	60.8	83	144	50	288
	Annual	1.95	30.5	32	20	162
PM2.5	24-hr	12.8	17.1	30	35	85
	Annual	0.45	7.2	8	12	64
SO_2	1-hr	0.064	73	73	665	11
	3-hr	0.051	15.6	16	1,300	1
	24	0.013	18.4	18	105	18
	Annual	0.005	3	3	80	4

Source: BEP II 2009, AFC Amendment, Table 5.2E-4
Note: [a] ARM applied for annual average, using national default ratio of 0.75.

As indicated in **AIR QUALITY Table 10**, the project construction activities would further exacerbate existing violations of the state PM10 standards, and thus constitute a significant air quality impact for PM10. Additionally, NOx and ROC emissions from construction equipment would react to contribute to existing violations of the ozone standards (not modeled, but see **AIR QUALITY Table 3** for background [ambient] values) 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, PM2.5 or SO_2 air quality standards, thus impacts from NO_2, CO, and SO_2 emissions are not considered significant.

OPERATION IMPACTS

The following section discusses the ambient air quality impacts that could occur during routine operation throughout the life of the project, including initial commissioning.

Routine Operation Impacts

A refined modeling analysis was performed to identify off-site criteria pollutant impacts from routine operational emissions. The impact modeling analysis included startup/shutdown scenarios to determine maximum short-term and annual emission impacts. Short-term emission rates in the model are derived from startup conditions for the combustion turbines, with simultaneous testing of the emergency fire pump engine. Annual emission rates in the model are derived from full-time, full-load operation of the combustion turbines with approximately 640 hours annually in either a startup or shutdown mode.

The predicted concentrations of the nonreactive pollutants for BEP II are summarized in **AIR QUALITY Tables 11**. The values in **bold** in the impacts and background columns represent values that equal or exceed the relevant air quality standard. Without any project-related impacts, existing background conditions for PM10 exceed the state standard.

AIR QUALITY Table 11
BEP II, Ambient Air Quality Impacts from Routine Operation (μg/m^3)

Pollutants	Avg. Period	Project Impact (μg/m^3)	Background (μg/m^3)	Total Impact (μg/m^3)	Standard (μg/m^3)	Percent of Standard
NO_2	1-hr.	113	92.1	205	339	60
	1-hr Fed			179	188	95
	Annual	0.338	17.1	17	57	30
CO	1-hr	213	2,645	2858	23,000	12
	8-hr	19.2	744	763	10,000	8
PM10	24-hr	2.85	83	86	50	172
	Annual	0.666	30.5	31	20	155
PM2.5	24-hr[a]	2.85	17.1	20	35	57
	Annual	0.666	7.2	8	12	67
SO_2	1-hr	6.28	73	79	665	12
	3-hr	3.26	15.6	19	1,300	1
	24-hr	0.92	18.4	19	105	18
	Annual	0.036	3	3	80	4

Source: BEP II 2009, AFC Amendment, Table 5.2-18; MDAQMD 2010b, Table 4; BEP II 2010a and 2010b.
[a] The new federal 24-hour PM2.5 standard is expressed as 3-year average of the 98th percentile highest daily 24-hour average PM2.5 concentration, including background. However, the impact reported here is based on the total of worst-case project impact and background concentration, which is a more conservative estimation of the project impact.

The modeling results indicate that the project's operational impacts would not create violations of NO_2, CO, PM2.5 or SO_2 standards, but could further exacerbate existing violations of the state PM10 standard. In light of the existing PM10 non-attainment status for the region, the impacts of direct PM10 emissions are considered to be significant and warrant mitigation. Secondary impacts caused by reaction of PM10 and ozone precursors are also discussed below. The federal 1-hr NO_2 analysis shows the maximum impact occurs on the southeast corner of the fence line, which is due to limited dispersion of the plume from the relatively short stack of the diesel-fueled fire water pump. Recently a new federal 24-hour PM2.5 standard was released, which is expressed as 3-year average of the 98th percentile highest daily 24-hour average PM2.5 concentration, including background. However, in **AIR QUALITY Tables 11,** staff adds the worst case background PM2.5 concentration to the maximum 24-hour PM2.5 project impacts to get a very conservative estimation of the total impacts. Even using this very conservative approach, the 24-hour PM2.5 impacts are less than the new federal standard.

Secondary Pollutant Impacts

The project's gaseous emissions of NOx, SO_2, ROC, and ammonia are precursor pollutants that can contribute to the formation of secondary pollutants. Each of these can lead to secondary PM10 and PM2.5, and NOx and ROC are also precursors to ozone. The process of gas-to-particulate conversion is complex and depends on many factors, including local humidity and the presence of other compounds. Currently, there are no agency-recommended models or procedures for estimating nitrate or sulfate formation, and there is no record of data in the project vicinity that establishes the composition of ambient PM10 or PM2.5. However, because of the known relationship of NOx and SO_2 emissions to secondary PM10/PM2.5 formation, it can be said that the emissions of NOx and SO_2 from the project do have the potential (if left unmitigated) to contribute to PM10 and PM2.5 concentrations in the region.

As identified above, PM10 impacts would be significant due to direct emissions. Secondary impacts would be significant for PM10 and ozone because routine operational emissions of precursor pollutants would contribute to existing violations of the state-level PM10 and ozone standards (shown in **AIR QUALITY Table 3**). Along with mitigation that is appropriate to reduce significant, direct impacts of PM10, additional mitigation for emissions of precursors is appropriate to reduce secondary impacts to PM10 and ozone.

Impacts During Fumigation Conditions

There is the potential that higher short-term concentrations may occur during fumigation conditions. Fumigation normally occurs during the morning hours after sunrise, when the surface air is stable with a low but rising inversion layer. Below the zone of restricted mixing caused by a low inversion layer, the air at ground level experiences turbulent vertical mixing (both rising and sinking) of air within a few hundred feet of the ground, which can bring emissions from a stack close to ground level with little dispersion. Fumigation conditions are generally short-term in nature and are only compared to 1-hour or 3-hour standards. The applicant analyzed the air quality impacts under fumigation conditions from the project turbine using the SCREEN3 model (Version 96043). All pollutants and normal operating conditions were examined. The fumigation impacts are shown in **AIR QUALITY Table 12**. Fumigation impacts are similar to operational impacts and are estimated to not cause violations of short-term ambient air quality standards.

AIR QUALITY Table 12
BEP II, Ambient Air Quality Impacts during Fumigation (µg/m^3)

Pollutants	Avg. Period	Project Impact (µg/m^3)	Background (µg/m^3)	Total Impact (µg/m^3)	Standard (µg/m^3)	Percent of Standard
NO_2	1-hr.	23.24	92.1	115	339	34
CO	1-hr	12.3	2,645	2,657	23,000	12
SO_2	1-hr	1.27	73	74	665	11

Source: BEP II 2009, Table 5.2-21.

Impacts During Initial Commissioning

Commissioning impacts would occur over a short-term period within 85 days expected to be needed to complete the commissioning. The commissioning emissions estimates are based on partial load operations before the emission control systems become fully operational. Only NOx and CO impacts are analyzed here because these are the only criteria pollutants that will be elevated during the commissioning phase over levels that would occur under routine operations. The results of the applicant's modeling analysis are presented in **AIR QUALITY Table 13**. As shown in **Air Quality Table 13**, the commissioning-phase emissions will not cause new exceedences of any state or federal air quality standard.

Visibility Impacts

An analysis of the project's gaseous emissions impacts on long-range visibility is required under the Federal Prevention of Significant Deterioration (PSD) permitting program. The analysis includes the effects of gaseous emissions (primarily NOx and SO_2) and particulate (PM10 and PM2.5) emissions on visibility impairment in the nearest Federally-designated Class I areas, which are generally national parks, national wildlife refuges, and wilderness areas. The nearest Class I area to BEP II is Joshua Tree National Park, approximately 59 miles (95 km) to the northwest. The original maximum visibility impact of BEP II was estimated to be 2.05 percent, which is less than the significant change level of 5 percent. The project modifications do not negatively affect the original finding based upon emission rates and distance from Joshua Tree National Park. The National Park Service (NPS) has exempted this project from a Class I impact assessment for air quality related values to either deposition or visibility in the PSD permit application.

AIR QUALITY Table 13
BEP II, Ambient Air Quality Impacts During Commissioning (µg/m^3)

Pollutants	Avg. Period	Project Impact (µg/m^3)	Background (µg/m^3)	Total Impact (µg/m^3)	Standard (µg/m^3)	Percent of Standard
NO_2	1-hr	167.6	92.1	260	339	77
	1-hr Fed.			143	188	76
CO	1-hr	2,922	2,645	5,567	23,000	24
	8-hr	1,026	944	1,970	10,000	20

Source: BEP II 2009, Table 5.2-18; BEP II 2010a and 2010b.

MITIGATION

Applicant's Proposed Mitigation

Applicant's Construction Mitigation

The Applicant proposes to reduce construction-related emissions by implementing measures consistent with the 1) Grading permit, 2) Stormwater Pollution Prevention Plan (SWPPP) requirements, 3) Use permit, 4) Building permit and 5) MDAQMD Permit to Construct (PTC). Fugitive dust mitigation and/or emission control techniques proposed by the Applicant during construction include:

- An on-site construction mitigation manager will be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the proposed construction mitigations will be provided on a periodic basis.
- All unpaved roads and disturbed areas in the Project and Construction Laydown and Parking Area will be watered as frequently as necessary to control fugitive dust. The frequency of watering will be on a minimum schedule of every two hours during the daily construction activity period. Watering may be reduced or eliminated during periods of precipitation.
- On-site vehicle speeds will be limited to 5 mph on unpaved areas within the Project construction site.
- The construction site entrance will be posted with visible speed limit signs.
- All construction equipment vehicle tires will be inspected and cleaned as necessary to be free of dirt prior to leaving the construction site via paved roadways.
- Gravel ramps will be provided at the tire cleaning area.
- All unpaved exits from the construction site will be graveled or treated to reduce track-out to public roadways.
- All construction vehicles will enter the construction site through the treated entrance roadways, unless an alternative route has been provided.
- Construction areas adjacent to any paved roadway will be provided with sandbags or other similar measures as specified in the construction SWPPP to prevent runoff to roadways.
- All paved roads within the construction site will be cleaned on a periodic basis (or less during periods of precipitation), to prevent the accumulation of dirt and debris.
- The first 300 feet of any public roadway exiting the construction site will be cleaned on a periodic basis (or less during periods of precipitation), using wet sweepers or air-filtered dry vacuum sweepers, when construction activity occurs or on any day when dirt or runoff from the construction site is visible on the public roadways.

- All vehicles that are used to transport solid bulk material on public roadways and that have the potential to cause visible emissions will be covered, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to minimize fugitive dust emissions. A minimum freeboard height of 2 feet will be required on all bulk materials transport.
- Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) will be used on all construction areas that may be disturbed.

To mitigate diesel vehicle exhaust emissions from construction equipment, the Applicant is proposing the following:

- Work with the general contractor to utilize to the extent feasible, Environmental Protection Agency (EPA)/Air Resources Board Tier II/Tier III engine compliant equipment for equipment over 100 horsepower.
- Ensure periodic maintenance and inspections per the manufacturers specifications.
- Reduce idling time through equipment and construction scheduling.

Applicant's Operations Mitigation

The BEP II design includes a combination of clean-fuel-firing equipment, emission control devices, and emission reduction credits. The equipment description, equipment operation, and emission control devices are provided in the **AIR QUALITY Project Description**.

Emission Controls

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

The applicant is proposing to install a selective catalytic reduction system with aqueous[4] ammonia injection in the HRSG to reduce NOx emissions; and an oxidation catalyst system reduce CO and ROC emissions. However, the FDOC (MDAQMD 2010b) requires emissions limits of 2.0 ppmvd NOx (1-hour average), with 5 ppmvd ammonia slip (3-hour average), 2 ppmvd CO (1-hour average), and 1 ppmvd ROC without duct burner or 2 ppmd with duct burner (1-hour average).

The cooling towers would use drift eliminators to minimize cooling tower drift to 0.0005 percent, which would minimize the accompanying PM10 emissions.

[4] The original amendment request of October 26, 2009 indicates that anhydrous ammonia would be used, but the January 6, 2010 amendment modification corrects this notation to aqueous ammonia.

Emission Offsets

In addition to emission control strategies included in the project design, the applicant would provide emission reductions to offset emissions of PM10/PM2.5, SOx, and ozone precursor pollutants (NOx and ROC). The applicant is required to offset these pollutants by MDAQMD Regulation XIII by obtaining and surrendering sufficient valid emission reduction credits (ERCs). The quantity of ERCs required by Rules 1303 and 1305 and the quantity identified by BEP II are each shown in **AIR QUALITY Table 14**.

Existing NOx ERCs owned by Caithness Blythe II are certified from MDAQMD with Certificate Number 0058 (25 tpy) and Certificate Number 0051 (175 tpy). Another 250 tpy NOx ERC was created by reducing emissions from numerous large natural-gas fired engines operated by Southern California Gas Company (SoCal Gas) near Blythe. Surplus NOx ERCs would be used to offset ROC emissions through inter-pollutant trade and banking with the MDAQMD. The U.S. EPA originally indicated that inter-pollutant trades require its approval on a case-by-case basis (U.S. EPA 2002a), but to date they have offered no further comments. For this project, the applicant proposes a NOx for ROC trade ratio of 1:1; this has been approved by the District.

The original BEP II decision was rendered using ozone data from 29 Palms, as ozone monitoring data from the Blythe area were not available at that time. Recent monitoring data for 2004 to 2010 confirm that ozone readings in the vicinity of Blythe are lower than those at 29 Palms, just as projected in the staff analysis for the original decision for BEP II. Although the region exceeds the state ozone standard and the MDAQMD thus requires ozone precursor offsets, as shown in **Air Quality Table 3** the area near the proposed BEP II site hovers just slightly above and below the standard. There is a lack of local information or data that could be used to refine the inter-pollutant offset ratio. Local characteristics (isolated location, low humidity levels, relatively pristine air quality) preclude a refinement in ozone precursor management and the emissions offset management approach is consistent with the treatment used in the Energy Commission's December 2005 decision. For all the reasons cited above, for this project in this location staff concurs in the use of a 1:1 ratio for inter-pollutant offsets.

The MDAQMD supports the use of road paving PM10 reductions to offset natural gas combustion PM10 emissions within a PM10 non-attainment area. The PM10 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 (Galati 2003a). Approximately 9,280 linear feet (1.75 miles) of total roadways were identified by the agreement. This agreement was established in December 2002 and was set to terminate in 2003; however, the MDAQMD indicates that 126 tpy of PM10 offsets will still be obtained by the applicant through this agreement.

AIR QUALITY Table 14 also includes a staff-proposed mitigation under the California Environmental Quality Act (CEQA). In addition to the MDAQMD's ERC requirements, CEC also requires ERCs for CEQA mitigation of SO_x emissions. Staff proposes to allow the surplus NO_x offsets to satisfy the SO_x mitigation requirements at a ratio of 1:1.

Because NO_x and SO_x are both precursors of PM10, the NO_x offsets will be equivalent to SO_x emissions mitigation.

AIR QUALITY Table 14
BEP II Emission Offset Requirements and ERC Sources

	ERC Identification	NOx (tpy)	PM10 (tpy)	Sox (tpy)	ROC (tpy)	CO[a] (tpy)
BEP II Potential to Emit		169.4	60.9	13.3	51.9	110.7
Rule 1303 Offset Thresholds		25	15	25	25	100
Rule 1305 Offset Ratios (NOx for ROC)					1.0	
BEP II Offsets required by MDAQMD		169.4	60.9	0	51.9	0
BEP II Offsets required by CEC		169.4	60.9	13.3	51.9	0
CRIT Road Paving	MDAQMD (pending)	0	126	0	0	0
Existing ERC Held or Owned by Blythe II	MDAQMD – 0058	25	0	0	0	0
Existing ERC Held or Owned by Blythe II	MDAQMD – 0051	175	0	0	0	0
SoCal Gas Company	MDAQMD – 0052	250	0	0	0	0
Total ERCs Identified:		450	126	0	0	0
Transfer from NOx to ROC (MDAQMD offset compliance plan)		(51.9)			51.9	
Total ERCs Identified:		398.1	126	0	51.9	0
Sufficient for MDAQMD Requirements?		Yes	Yes	Yes	Yes	
Transfer from NOx to ROC and SO_x (CEC offset compliance plan)[b]		(65.2)		13.3	51.9	
Total ERCs Identified:		384.8	126	13.3	51.9	0
Sufficient for CEC Requirements?		Yes	Yes	Yes	Yes	

Source: BEP II 2009, table 5.2G-1, MDAQMD 2010b.

Note: [a] Emission offsets are not required for CO due to the attainment status of District.

[b] Staff proposes to allow surplus NO_x offsets to mitigate ROC and SOx emissions.

<u>Adequacy of Proposed Mitigation</u>

Adequacy of Construction Mitigation

The effectiveness of the proposed construction mitigation can be expressed by the percentage of uncontrolled emissions that are avoided, and it varies widely due to the number of factors. These include: ambient conditions (temperature, wind, and humidity), size and weight of vehicles, vehicle speed, frequency and number of active vehicles, soil characteristics (chemical composition, particle size distribution, organic components), and day-to-day aggressiveness of mitigation efforts (e.g., application of water or dust suppressants, street sweeping to remove carryout from paved roads). If the mitigation measures for fugitive dust-generating activities are applied correctly and with sufficient frequency, the control efficiency can approach 100 percent.

As shown in **AIR QUALITY Table 10** above, direct impacts of NO_2, CO, SO_2, and PM2.5 would not be significant. Direct PM10 impacts would be reduced by the proposed mitigation but would remain significant because any increase to PM10 concentrations could contribute to continuing violations of the PM10 standards. Similarly, secondary impacts for PM10 and ozone would continue to be significant because of construction emissions of PM10 and ozone precursors. Additional mitigation is necessary (see **Staff Proposed Mitigation**) to reduce direct PM10 impacts and secondary impacts to PM10 and ozone.

Adequacy of Operations Mitigation

The MDAQMD BACT determinations in the FDOC for gas turbine emissions of 2.0 ppmvd NOx (1-hour basis), 2.0 ppmvd CO (1-hour basis) and 5.0 ppmvd NH_3 (1-hour basis) are the most stringent according to the current U.S. EPA and ARB recommendations. The CEQA mitigation approach for PM10/PM2.5, SOx, and ozone precursor pollutants (NOx and ROC) includes emission reductions as shown in **AIR QUALITY Table 14** (above). The reductions serve the dual purpose of satisfying the requirements in MDAQMD Regulation XIII and mitigating the CEQA impacts identified by Energy Commission staff.

Direct PM10 Mitigation

Staff estimates that 61 tpy of direct PM10 emissions must be offset in order for the project to fully mitigate its contribution to state-level nonattainment PM10 conditions. The applicant and MDAQMD identified sufficient CRIT road paving PM10 ERCs in the FDOC to satisfy the fundamental requirements of Rules 1302 and 1303 (**AIR QUALITY Table 14**).

Staff has reservations about using road-paving to mitigate impacts from combustion-related particulate matter. Fugitive dust from unpaved public roads is not a source category that is normally subject to permitting in the MDAQMD, but the MDAQMD 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 ARB also previously expressed specific concerns about using road paving offsets for combustion sources in a memorandum from the ARB Executive Officer to all local Air Pollution Control Officers (ARB2000). The ARB noted that combustion of natural gas emits very fine particulate matter less than 2.5 microns in size (PM2.5), and dust control from road paving provides reduction of particles much larger in size, the majority PM10, with only 13 to 15 percent of the emission reductions being less than 2.5 microns (EPA 1991, AP-42 Section 13.2.2). In other cases staff has recommended correcting the ERC for PM10-to-PM2.5 effectiveness because only about 15 percent of the PM10 reduction would qualify as PM2.5. Staff's analysis of BEP II impacts reveals that the project would not be likely to cause new PM2.5 violations or contribute to PM2.5 violations. The PM2.5

effectiveness of the road paving ERC is less important in this setting because the site region is not non-attainment for PM2.5 and the PM10 reductions achieved by road paving would be suitable for mitigating the PM10 impacts of the project. It is worth noting that the MDAQMD supports use of road paving PM10 reductions as a means of offsetting the PM10 from natural gas combustion (MDAQMD 1995 and 2010b).

Secondary PM10 Mitigation

It is difficult to correlate the effect of gaseous emissions on particulate formation because of the complexity of the precursor reactions. However, since MDAQMD requires offsets for project emissions of NOx and the emissions of SOx are less than the offset threshold, staff expects that compliance with the offset requirements would satisfactorily mitigate the effects of these precursors as long as sufficient offsets are available.

Staff estimates that approximately 13.3 tpy of SO_x emissions (**AIR QUALITY Table 8**) must be mitigated in order for the project to fully mitigate the secondary effects of PM10 formation from BEP II emissions. Since both NO_x and SO_x are precursors of PM10, staff will use surplus NO_x ERCs to mitigate SO_x emissions. The project's NOx and ROC emissions are also PM10 precursors warranting offsets. The applicant offers PM10 emission reductions from road paving as mitigation, and staff believes that a surplus of approximately 65.1 tpy of PM10 reductions would remain after mitigating the direct PM10 impacts. The setting indicates that secondary particulates are probably a minor fraction of the overall PM10 concentrations in the area, and windblown dust is more of a PM10 concern than gas-to-particulate conversion. PM10 reductions from road paving are more valuable in this setting than they would be in other areas, where close management of precursors is more desirable.

Secondary Ozone Mitigation

The applicant proposed providing offsets of NOx to mitigate secondary ozone impacts. The ability of the offsets to mitigate project ozone impacts depends on whether sufficient combined reductions of NOx and ROC would occur. The applicant and the FDOC identify that a sufficient quantity of NOx ERCs would be surrendered, see **AIR QUALITY Table 14** above. Staff estimates that 169.4 tpy of NOx emissions would be fully offset with the surrender of the 450 tpy of ERCs. About 51.9 tpy of excess NOx reductions would also be available for an interpollutant trade to offset the ROC increases of the project at a 1-to-1 ratio. As with the PM10 mitigation strategy, the U.S. EPA has not provided any guidance on interpollutant trading ratios. However staff believes that the ratio of 1:1 to is proper because both NO_x and ROC are ozone precursors.

Staff estimates that approximately 51.9 tpy of ROC emissions (**AIR QUALITY Table 8**) must be offset in order for the project to fully mitigate the ozone precursor effects. After applying 51.9-tpy excess NOx reductions from above, staff believes that the ROC impacts will be fully mitigated.

Staff Proposed Mitigation

Staff Proposed Construction Mitigation

Additional measures recommended by staff would reduce construction-phase impacts to a less than significant level by further reducing construction emissions of particulate matter and combustion contaminants. Staff believes that the short-term and variable nature of construction activities warrants a qualitative approach to mitigation.

Construction emissions and the effectiveness of mitigation varies widely depending on variable levels of activity, the specific work taking place, the specific equipment, soil conditions, weather conditions, and other factors, making quantification of emissions and air quality impacts difficult. Despite this uncertainty, there are a number of feasible control measures that can and should be implemented to significantly reduce construction emissions. Staff has determined that the use of oxidizing soot filters is a viable emissions control technology for all heavy diesel-powered construction equipment that does not use an ARB-certified low emission diesel engine. In addition, staff proposes that, prior to beginning construction, the applicant should provide an Air Quality Construction Mitigation Plan (AQCMP) that specifically identifies mitigation measures to limit air quality impacts during construction. Staff includes proposed staff Conditions of Certification **AQ-SC1** through **AQ-SC5** to implement these requirements. These conditions are consistent with both the applicant's proposed mitigation and the conditions of certification adopted in similar prior licensing cases. Compliance with these conditions is expected to reduce or eliminate the potential for significant adverse air quality impacts during construction of the project.

Staff Proposed Operations Mitigation

Staff reviewed the overall approach to mitigation, including the emission control systems proposed for the sources and the project-specific offset package submitted in the AFC amendment. When the proposed offsets are taken together in the ambient setting, staff believes that the project's emissions of NO_x, SO_x, PM10, and ROC would be fully mitigated by the proposed offsets.

CUMULATIVE IMPACTS

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

Cumulative effects are defined by the Council on Environmental Quality NEPA regulations as "…the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such actions" (40 CFR 1508.7).

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

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

- A summary of projections for criteria pollutants by the air district and the air district's programmatic efforts to abate such pollution; and
- An analysis of the proposed project's *localized cumulative impacts*, the proposed project's direct operating emissions combined with other local major emission sources.

SUMMARY OF PROJECTIONS

The Riverside County portion of the MDAB is designated as unclassified or attainment for all federal ambient air quality standards and the state CO, NO_2, SO_2 and PM2.5 standards, but is designated as non-attainment for State ozone and PM10 standards.

<u>Ozone</u>

Since a portion of San Bernardino County in the Mojave Desert Air Basin is currently classified as non-attainment for the federal 8-hour ozone standard north and west of the project site, the District is required to prepare and adopt an ozone attainment plan for submittal to the U.S. EPA describing how it will attain the federal 8- hour standard. The District completed this plan in 2008. The project is not specifically subject to the provisions in the federal attainment plan and the site is outside of the non-attainment area.

The District is required to prepare and adopt a state ozone attainment plan for submittal to ARB. The latest state ozone attainment plan was adopted by MDAQMD in 2004. The MDAQMD 2004 Ozone Attainment Plan contains attainment plans for both federal (for areas within San Bernardino County) and state ozone standards. The MDAQMD did not propose to adopt any additional control measures as part of the 2004 Plan. Additionally, while there are no additional control measures for direct ozone precursor reduction as part of the federal 2008 attainment plan, MDAQMD is committed to adopt all applicable Federal Reasonably Available Control Technology (RACT) rules it proposed in 8-hour Reasonably Available Control Technology – State Implementation Plan Analysis (RACT SIP Analysis) in 2006. In addition, the MDAQMD updated and indentified new measures in 2007, which will be adopted through 2014, as the State of California mandates use of all feasible measures. The RACT rules and other new measures do not impact the BEP II emission sources as proposed.

The project area is expected to be re-designated as non-attainment for the federal 8-hour ozone standard in the spring of 2012. Any additional emissions controls needed to meet attainment for this region have yet to be identified and would likely not apply to this facility because permits have been filed and accepted before the effective date.

Particulate Matter

Since a portion of San Bernardino County in the Mojave Desert Air Basin is currently classified as non-attainment for the federal PM10 standards north and west of the project site, the District is required to prepare and adopt an attainment plan for submittal to the U.S. EPA describing how it will achieve attainment with the federal PM10 standards. However, the modified BEP II site that is in Riverside County and is outside of the federal non-attainment area and is not subject to the provisions in the federal attainment plan. There is no legal requirement for air districts to provide plans to attain the state PM10 standard, so air districts have not developed such plans. Therefore, there are no air quality management plan particulate emission control measures that are applicable to the modified BEP II project.

With the implementation of staff-recommended construction and operation CEQA mitigation measures, staff believes that it is unlikely that the modified BEP II project would have significant impact on particulate matter ambient concentrations.

LOCALIZED CUMULATIVE IMPACTS

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

- First, the Energy Commission staff (or the applicant) works with the air district to identify all projects that have submitted, within the last year of monitoring data, new applications for an authority to construct (ATC) or permit to operate (PTO) and applications to modify an existing PTO within six miles of the project site. Based on staff's modeling experience, beyond six miles there is no statistically significant concentration overlap for non-reactive pollutant concentrations between two stationary emission sources.
- Second, the Energy Commission staff (or the applicant) works with the air district and local counties to identify any new area sources within six miles of the project site. As opposed to point sources, area sources include sources like agricultural fields, residential developments or other such sources that do not have a distinct point of emission. New area sources are typically identified through draft or final Environmental Impact Reports (EIRs) that are prepared for those sources. The initiation of the EIR process is a reasonable basis on which to determine what is "reasonably foreseeable" for new area sources.
- The data submitted, or generated from the applications with the air district for point sources or initiating the EIR process for area sources, provides enough information to include these new emission sources in air dispersion modeling. Thus, the next step is to review the available EIR(s) and permit application(s), determine what sources must be modeled and how they must be modeled.
- Sources that are not new, but may not be represented in ambient air quality monitoring are also identified and included in the analysis. These sources include existing sources that are co-located with or adjacent to the proposed source (such as an existing power plant). In most cases, the ambient air quality measurements are not recorded close to the proposed project, thus a local major source might not be well represented by the background air monitoring. When these sources are included, it is typically a result of there being an existing source on the project site and the ambient air quality monitoring station being more than two miles away.
- The modeling results must be carefully interpreted so that they are not skewed towards a single source, in high impact areas near that source's fence line. It is not truly a cumulative impact of BEP II if the high impact area is the result of high fence line concentrations from another stationary source and BEP II is not providing a substantial contribution to the determined high impact area.

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

The applicant determined that there are three major stationary source projects within a six mile radius of the BEP II site and those three projects were included with the project’s operation in cumulative impacts modeling analysis (BEP II 2010c and 2010d). The three specific stationary source projects included in the cumulative modeling analysis are:

- Blythe Solar Power Project, which was approved by CEC and is now under construction
- Blythe Energy Project (BEP I), which is currently operating at a low capacity factor due to transmission line constraints.
- SoCalGas Compressor Station, which is in the process of being modernized.

There are other proposed construction projects near the modified BEP II project site such as other proposed renewable energy projects; however, the timeframe and emissions from these projects is unknown and these construction projects would be limited in duration. Meanwhile emissions from existing mobile emission sources, such as the I-10 freeway and agriculture are forecast to have long-term emission reductions or significantly reduced emission potentials for most pollutants through improvements in on-road and off-road vehicle engine technology and vehicle turnover, respectively.

The applicant used stack and building parameters and emission data available for the cumulative projects, and generally followed the same modeling procedures used for the BEP II operating emissions modeling analysis, using the most recent version of AERMOD (Version 09292). The optional OLM method available with AERMOD, discussed under the operating impacts section, was used to model the NOx impacts. The results of the cumulative modeling analysis for modified BEP II are presented in **AIR QUALITY Table 15**.

Compared with the impacts from the modified BEP II project alone, maximum cumulative impacts caused by the sources in this assessment would be relatively higher for all criteria pollutants. Many of the maximum impact locations are adjacent to the SoCalGas Compressor Station. These impact locations are most likely a product of the receptor grid placed around this source, where the stack location is immediately adjacent to one of the receptors.

As shown in **AIR QUALITY Table 15**, cumulative sources would not create any new violation of the limiting standards. The maximum federal 1-hour NO_2 impact is close to but still below the standard. The maximum total NO_2 concentration occurs on the southeast corner of the fence line of BEP II project. However, when viewed over a multi-year period, the modeled concentrations of NO_2 impacts from the diesel-fueled emergency fire pump engine become conservatively high because these sources are modeled with operation recurring every hour of the year although they would emit only sporadically (50 hours per year) during testing events that would rarely occur simultaneously with worst-case meteorological conditions.

Staff believes that particulate matter emissions from BEP II would be cumulatively considerable because they would contribute to existing violations of the PM10 ambient air quality standards, unless mitigated. However, the maximum modeled PM10 impact occurs at a receptor immediately adjacent to one of the cooling towers of BEP I project, which is mainly due to PM emission from the Blythe I cooling towers. To address the contribution caused by BEP II to cumulative particulate matter, mitigation would offset particulate matter and the precursors at a minimum ratio of one-to-one.

AIR QUALITY Table 15
BEP II, Ambient Air Quality Impacts from Cumulative Sources (µg/m^3)

Pollutants	Avg. Period	Project Impact (µg/m^3)	Background (µg/m^3)	Total Impact (µg/m^3)	Standard (µg/m^3)	Percent of Standard
NO_2	1-hr.	137.7	92.1	229.8	339	68
	1-hr Fed			183.2	188	97
	Annual	5.6	17.1	22.7	57	40
CO	1-hr	215.0	2,645	2,860.0	23,000	12
	8-hr	102.3	744	846.3	10,000	8
PM10	24-hr	34.0	83	117.0	50	234
	Annual	2.67	30.5	33.2	20	166
PM2.5	24-hr	6.36	17.1	23.5	35	67
	Annual	0.88	7.2	8.1	12	68
SO_2	1-hr	29.81	73	102.8	665	15
	3-hr	26.63	15.6	42.2	1,300	3
	24-hr	11.39	18.4	29.8	105	28
	Annual	1.37	3	4.4	80	6

Source: BEP II 2010d and staff independent analysis.

COMPLIANCE WITH LORS

FEDERAL

The U.S. EPA is currently responsible for completing the Federal Prevention of Significant Deterioration (PSD) review requirements for projects proposed in the MDAQMD. The original BEP II PSD permit was issued on April 25, 2007. The project owner submitted an application to the U.S. EPA for a new PSD permit for the proposed amended facility in December 2009. To achieve compliance with the PSD program, the project must satisfy U.S. EPA requirements for BACT. Although the U.S. EPA has not formally released an application completeness letter, their comments on the MDAQMD Preliminary Determination of Compliance in 2010 (U.S. EPA 2010) led to modifications in the 2010 FDOC. Based on the BACT determination in the FDOC, staff expects that proposed BEP II would meet the U.S. EPA PSD requirements.

Because the federal permitting process is ongoing, and there remains a possibility of revised conditions, staff recommends condition of certification **AQ-SC6** for coordinating future possible modifications.

STATE

The applicant has demonstrated that the project would comply with Section 41700 of the California State Health and Safety Code, which restricts emission that would cause nuisance or injury. Compliance with FDOC and the staff's Conditions of Certification enable staff's affirmative finding.

Under the Warren-Alquist Act, Public Resources Code Section 25523(d)(2), the Energy Commission may not find that the proposed facility conforms with applicable air quality standards unless the local air district (MDAQMD in this case) certifies that complete offsets have been identified and will be obtained. The MDAQMD has determined that a sufficient quantity of offsets have been identified and that the offsets will be obtained. Based on the Staff's proposed ERC compliance plan, the offsets will also satisfy CEQA mitigation requirements.

LOCAL

The District released its initial new source review document, or Preliminary Determination of Compliance (PDOC, MDAQMD 2010a), for the proposed project on March 15, 2010. Comments on the PDOC were subsequently received by the District from USEPA, Region IX on May 26, 2010. The MDAQMD completed a Final Determination of Compliance (FDOC, MDAQMD 2010b) for this project on August 10, 2010 and found that the proposed BEP II, after application of the proposed permit conditions (including BACT requirements), would comply with all applicable MDAQMD Rules and Regulations. The FDOC conditions are presented in the proposed Conditions of Certification of this Staff Assessment (**AQ-1** to **AQ-63**).

FACILITY CLOSURE

Eventually, BEP II will close, either as a result of the end of its useful life, or through some unexpected situation such as a natural disaster or catastrophic facility breakdown. When the facility closes, all sources of air emissions would cease, and impacts associated with those emissions would no longer occur. The only other expected emissions would be emissions from the demolition and dismantling activities. Staff recommends that a Facility Closure Plan be submitted to the Energy Commission Compliance Project Manager prior to demolition and dismantling activities to demonstrate compliance with all local, state, and federal rules and regulations during closure and demolition.

CONCLUSIONS AND RECOMMENDATIONS

Staff has reviewed the applicant's documentation and the FDOC issued by the MDAQMD and concludes that the requested project amendment would likely conform with applicable Federal, State, and MDAQMD air quality laws, ordinances, regulations, and standards. The modified BEP II project would not cause significant air quality impacts, provided that the following Conditions of Certification (COC) are included. Staff recommends that the COCs be approved as shown below. In some of the conditions the term "VOC" (Volatile Organic Compound) is used to match wording in the FDOC, although the MDAQMD's rules use the term "ROC (Reactive Organic Compound)." These terms should be considered equivalent and interchangeable.

Global climate change and greenhouse gas (GHG) emissions from the project are discussed and analyzed in **Air Quality Appendix AIR-1**. As discussed there, the Blythe II will comply with the Emission Performance Standard established by SB 1368 for base load generation. The project would also be subject to the Air Resources Board mandatory GHG reporting requirements and any GHG reduction or trading requirements developed by the ARB as GHG regulations are implemented.

CONDITIONS OF CERTIFICATION

STAFF-RECOMMENDED CONDITIONS OF CERTIFICATION

The following section shows the conditions of certification with proposed changes. ~~Strikethrough~~ is used to indicate deleted language and **<u>underline and bold</u>** is used for new language. Staff proposed Conditions of Certification to provide mitigation during the construction phase of the project are **AQ-SC1** to **AQ-SC5**, and those for operation are **AQ-SC6** to **AQ-SC8**. District conditions of certification from the FDOC are shown as conditions **AQ-1** to **AQ-63**.

AQ-<u>S</u>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-<u>S</u>C3**, **AQ-<u>S</u>C4** and **AQ-<u>S</u>C5** for the **<u>entire duration of project construction</u>** ~~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 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 **<u>Compliance Project Manager (</u>**CPM**<u>)</u>**.

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

Verification: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. **The AQCMP must be approved by the CPM before the start of ground disturbance.**

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each monthly compliance report (MCR) that demonstrates compliance with the ~~following~~ **Air Quality Construction Mitigation Plan (AQCMP)** mitigation measures for the purposes of **minimizing fugitive dust emission creation from construction activities and** preventing all fugitive dust plumes from leaving the project**'s boundary**. **The following fugitive dust mitigation measures shall be included in the AQCMP required by AQ-SC2, and** any deviation from the **AQCMP** ~~following~~ mitigation measures shall require prior CPM notification and approval.

A. The main access roads through the facility to the power block areas will be either paved or stabilized using soil binders, or equivalent methods, to provide a stabilized surface that is similar for the purposes of dust control to paving, that may or may not include a crushed rock (gravel or similar material with fines removed) top layer, prior to initiating construction in the main power block area, and delivery areas for operations materials (chemical, replacement parts, etc.) will be paved prior to taking initial deliveries.

B) All unpaved **construction** roads **and unpaved operation site roads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as CARB approved soil stabilizers, and shall not increase any other environmental impacts including loss of vegetation to areas beyond where the soil stabilizers are being applied for dust control. All other** disturbed areas in the project ~~and linear~~ construction sites shall be watered as frequently as necessary **during grading; and after active construction activities shall be stabilized with a non-toxic soil stabilizer or soil weighting agent, or alternative approved soil stabilizing methods, in order** to comply with the dust mitigation objectives of **AQ-SC4** ~~(the prevention of fugitive dust~~

~~plumes)~~. The frequency of watering can be reduced or eliminated during periods of precipitation.

__C__~~b~~) No vehicle shall exceed 5 miles per hour **__on unpaved areas__** within the construction site, **__with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.__**

__D__~~c~~) The construction site entrances shall be posted with visible speed limit signs.

__E__~~d~~) All construction equipment vehicle tires shall be inspected and washed as necessary to be __cleaned__ free of dirt prior to entering paved roadways.

__F__~~e~~) Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

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

H~~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.

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

__J__~~i~~) All paved roads within the construction site shall be swept **__daily or as needed (less during periods of precipitation)__**~~as necessary~~ on days when construction activity occurs to prevent the accumulation of dirt and debris.

__K__~~j~~) At least the first 500 feet of any public roadway exiting from the construction site **__or exiting other unpaved roads en route from the construction site or construction staging areas__** shall be swept as **__needed (less during periods of precipitation)__** ~~necessary~~ on days when construction activity occurs or on any other day when dirt or runoff **__resulting__** from the construction site **__activities__** is visible on the public **__paved__** roadways.

__L__~~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.

__M__~~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 **__two feet__** ~~one foot~~ of freeboard.

N~~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~~ **AQCMM shall provide a Monthly Compliance Report to** include ~~in the MCR~~ the following to demonstrated control of fugitive dust emissions:

~~(1)~~**A.** A summary of all actions taken to maintain compliance with this condition,

~~(2)~~**B.** Copies of any complaints filed with the air district **or facility representatives** in relation to project construction, and

~~(3)~~**C.** Any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 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 **off the project site and within 400 feet upwind of any regularly occupied structures not owned by the project owner indicates that existing mitigation measures are not resulting in effective mitigation. The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified.** The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed:

~~(1) off the project site,~~

~~(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.~~

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 **result in effective mitigation within one hour of the original determination** ~~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 **activity** ~~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.~~ **The AQCMM shall provide the CPM a Monthly Compliance Report to include:**

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

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

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

AQ-SC5 Diesel-Fueled Engines Control: The AQCMM shall submit to the CPM, in the Monthly Compliance Report ~~(MCR)~~, a ~~construction mitigation report that demonstrates compliance with the following~~ **table that demonstrates compliance with the AQCMP** mitigation measures for the purposes of controlling diesel construction-related emissions. Any deviation from the ~~following~~ **AQCMP** mitigation measures ~~shall~~ requires prior CPM notification and approval.

All off-road diesel construction equipment used in the construction of this facility shall be powered by the cleanest engines available that also comply with the California Air Resources Board's (CARB's) Diesel Emission Control Strategy (verified DECS) for in-use vehicles and shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by AQ-SC2. The AQCMP measures shall include the following, with the lowest-emitting engine chosen in each case, as available:

~~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.~~

a. All off-road compression ignition engines shall comply with the California Air Resources Board's (CARB's) Diesel Emission Control Strategy (verified DECS) for in-use, off-road vehicles.

b. To meet the highest level of emissions reduction available for the engine family of the equipment, each piece of diesel-powered

equipment shall be powered by a Tier 4 engine, a Tier 4i engine or a Tier 3 engine with a post-combustion device retrofit device verified by the CARB or the US EPA. For PM, the retrofit device shall be a particulate filter if verified, or a flow-thru filter, or at least an oxidation catalyst. For NOx, the device shall meet the latest Mark level verified to be available (as of January 2012, none meet this NOx requirement).

c. For diesel powered equipment where the requirements of Part “b” cannot be met, the equipment shall be equipped with a Tier 3 engine without retrofit control devices or with a Tier 2 or lower Tier engine using retrofit controls verified by CARB or US EPA as the best available control device to reduce exhaust emissions of PM and nitrogen oxides (NOx) 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 can be considered “not practical” for the following, as well as other, reasons:

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

2. The use of the retrofit device would unduly restrict the vision of the operator such that the vehicle would be unsafe to operate because the device would impair the operator’s vision to the front, sides, or rear of the vehicle, or

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

d. The CPM may grant relief from a requirement in Part “b” or “c” if the AQCMM can demonstrate a good faith effort to comply with the requirement and that compliance is not practical.

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

1. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased

down time for maintenance, and/or reduced power output due to an excessive increase in exhaust back pressure.

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

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

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

f. **All equipment with engines meeting the requirements above shall be properly maintained and the engines tuned to the engine manufacturer's specifications. Each engine shall be in its original configuration and the equipment or engine must be replaced if it exceeds the manufacturer's approved oil consumption rate.**

g. **Construction equipment will employ electric motors when feasible.**

h. **If the requirements detailed above cannot be met, the AQCMM shall certify that a good faith effort was made to meet these requirements and this determination must be approved by the CPM.**

i. **All off-road 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.**

Verification: The ~~project owner~~ **AQCMM** shall include in the MCR **the following to demonstrate control of diesel construction-related emissions:**

A. ~~(1)~~ a summary of all actions taken to ~~maintain compliance with this condition,~~ **control diesel construction related emissions**;

B. ~~(2) copies of all diesel fuel purchase records,~~ **A list of all heavy equipment used on site during that month, showing the Tier level of each engine and the basis for alternative compliance with this condition for each engine not meeting Part "b". The list shall include the owner of the equipment and a letter from each owner indicating that the equipment has been properly maintained; and**

C. ~~(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~~ **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.

~~(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-SC6 **The project owner shall provide the CPM copies of all District issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) documents for the facility.** The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project 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.

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

AQ-SC7 The project owner shall submit ~~Quarterly Operational Reports~~ to the CPM **Quarterly Operation Reports,** ~~and District~~ **following the end of each calendar quarter,** that include operational and emissions information as necessary to demonstrate compliance with Conditions **of Certification herein.** ~~**AQ-C10** and **AQ-C11**, and **AQ-1** through **AQ-54**, as applicable.~~ The Quarterly Operational Report ~~will~~ **shall** 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 **APCO** ~~the District~~ no later than 30 days following the end of each calendar quarter.

~~**AQ-SC8** 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-SC9 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)	VOC (tpy)	PM10 (tpy)
CRIT Road Paving	MDAQMD (pending)			126
Existing ERC Held or Owned by Caithness Blythe II, LLC	MDAQMD -0058	25		
Existing ERC Held or Owned by Caithness Blythe II, LLC	MDAQMD -0051	175		
SoCal Gas Compressor Engines	MDAQMD – 0052	250		

~~MDAQMD ERC Source~~	~~ERC Identification~~	~~NOx (tpy)~~	~~PM10 (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~~	~~MDAQMD (pending)~~	~~0~~	~~126~~	~~0~~	~~0~~
~~SoCal Gas Compressor Engines~~	~~MDAQMD – 0051~~	~~251~~	~~0~~	~~0~~	~~0~~

Note: MDAQMD allows inter-pollutant trading of NOx ~~and PM10~~ 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 **and California ARB** concur~~s~~ with the determination that the ERCs are valid**, including road-paving**. If the CPM, in consultation with the District, approves a substitution or modification, the CPM shall file a statement of the approval with the Energy 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-SC10** 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-**~~**S**~~**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 CO2 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 (MDAQMD 2010B)

Turbine Power Train Conditions
[Two (2) individual ~~1776~~ 2019.6 MMBtu/hr F Class Gas Turbine Generators]
[MDAQMD Permit Numbers: B008877 and B008878]

~~**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.

Verification: 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-SC7**).

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 **twenty-four hour basis and not exceeding 0.25 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.

Verification: The project owner shall provide in the Quarterly Operational Reports (**AQ-SC7**) 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 **KKKK (Standards of Performance for New Stationary Gas Turbines)**~~GG (Standards of Performance for Stationary Gas Turbines)~~. This equipment is also subject to the Prevention of Significant Deterioration (40 CFR **52.21**~~51.166~~) and Federal Acid Rain (Title IV) programs. Compliance with all applicable provisions of these regulations is required.

Verification: 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 NO_2 – **17.9**~~14.82~~ lb/hr (based on 2.0 ppmvd corrected to 15% oxygen and averaged over **one**~~three~~ hour~~s~~)

   ii. CO – **10.9**~~18.04~~ lb/hr (based on 24.0 ppmvd corrected to 15% oxygen and averaged over ~~24~~ **one** hour~~s~~)

b. Hourly rates, verified by annual compliance tests or other compliance methods in the case of SOx:

i. VOC as CH_4 – 6.3~~2.90~~ lb/hr (based on **2.0 ppmvd (**1**.0** ppmvd **with no duct firing)** corrected to 15% oxygen **and averaged over one hour)**

ii. SOx as SO_2 – 3.3~~2.66~~ lb/hr (based on 0.5 grains/100 dscf fuel sulfur)

iii. PM_{10} – 7.5~~6.0~~ lb/hr

Verification: The project owner shall submit the following in the Quarterly Operational Reports (**AQ-SC7**): 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, PM10, 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~~ **has reached** operating permit limits **i.e., the applicable emission limits listed in AQ-4.** ~~specified in Condition AQ-4a for two consecutive 15-minute averaging periods or four hours after ignition, whichever occurs first.~~ **Cold startup is defined as a startup when the CTG has not been in operation during the preceding continuous 48 hours, although a startup after an aborted partial cold start(a cold start that does not reach 85% output) is still considered a cold start. Hot/warm startup is defined as a startup that is not a cold startup.** 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~~

Transient conditions shall not exceed the following durations:

i. Cold startup – 180 minutes

ii. Hot/warm startup – 60 minutes

iii. Shutdown – 60 minutes

c. During a cold startup emissions shall not exceed the following, verified by CEMS:

i. NOx – 120.9 lb

ii. CO – 140.4 lb

d. During hot/warm startup emissions shall not exceed the following, verified by CEMS:

i. NOx – 81.9 lb

ii. CO – 58.5 lb

e. During a shutdown emissions shall not exceed the following, verified by CEMS:

i. NOx – 29.7 lb

ii. CO – 25.3 lb

Verification: The project owner shall include a detailed record of each startup and shutdown event in the Quarterly Operational Reports (**AQ-SC7**). 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, auxiliary equipment, engine, and cooling towers, shall not exceed the following emission limits, based on a calendar day summary:

a. NOx – **1168**~~2924~~ lb/day, verified by CEMS, compliance tests, hours of operation and/or fuel use as applicable.

b. CO – **892**~~17,016~~ lb/day, verified by CEMS, compliance tests, hours of operation and/or fuel use as applicable.

c. VOC as CH4 – **499**~~187~~ lb/day, verified by compliance tests, and hours of operation in mode

d. SOx as SO2 – **154**~~128~~ lb/day, verified by fuel sulfur content and fuel use data.

e. PM_{10} – 380~~336~~ lb/day, verified by compliance tests and hours of operation.

Verification: The project owner shall submit in the Quarterly Operational Reports (**AQ-SC7**) 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**, auxiliary equipment, engine,** and cooling tower~~s~~, shall not exceed the following emission limits, based on a rolling 12 month summary:

a. NOx – **169.4**~~202~~ tons/year, verified by CEMS**, compliance tests, hours of operation and/or fuel use as applicable.**

b. CO – **110.7**~~685~~ tons/year, verified by CEMS**, compliance tests, hours of operation and/or fuel use as applicable.**

c. VOC as CH4 – **51.9**~~25~~ tons/year, verified by compliance tests and hours of operation in mode

d. SOx as SO2 – **13.3**~~23~~ tons/year, verified by fuel sulfur content and fuel use data

e. PM10 – **60.9**~~61~~ tons/year, verified by compliance tests and hours of operation.

Verification: The project owner shall submit in the Quarterly Operational Reports (**AQ-SC7**) 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. **(Rule 401 – *Visible Emissions*)**

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

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

Verification: **At least 60 days prior to stack fabrication** ~~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 **oxidation catalyst with valid District permit C00nnnn and** selective catalytic ~~NOx~~ reduction system with valid District permit**s'** C00nnnn#~~C008881 or C008882~~ installed~~ and fully functional~~.

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

Verification: **At least 60 days prior to stack fabrication** ~~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, **40 CFR 60 and/or 40 CFR 75 as applicable. Note; Where 40 CFR 60 and 40 CFR 75 are applicable but inconsistent, 40 CFR 75 shall take precedent.** ~~and they shall be installed prior to initial equipment startup.~~

Verification: 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 Energy Commission.

AQ-13 The project owner shall conduct all required compliance/certification tests in accordance with a District-approved test plan. **Thirty(30) days prior to the compliance/certification tests the project owner shall provide a written test plan for District review and approval. Written notice of the compliance/certification test shall be provided to the District 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 within forty-five (45) days after testing.**

Verification: Thirty (30) days prior to the compliance/certification tests, the project owner shall provide **the District and CPM test plan, including test dates. Documentation of the District's approval of the test plan should be provided to the CPM within 15 days of its receipt.** ~~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 test report shall be submitted to the District no later than six weeks prior to**

<u>the expiration date of this permit.</u> The following compliance tests are required **<u>at full load</u>**:

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 **<u>(measured per USEPA Reference method 6 or equivalent).</u>**

d. CO in ppmvd at 15% oxygen and lb/hr (measured per USEPA Reference Method 10).

e. PM_{10} in mg/m^3 at 15% oxygen and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).

f. Flue gas flow rate in **<u>dscf per minute (measured per USEPA Reference Methods 1 and 2)</u>**.~~DSCFM.~~

g. Opacity (measured per USEPA reference Method 9).

h. Ammonia slip in ppmvd at 15% oxygen.

Verification: <u>The project owner shall notify the District and CPM at least 30 days prior to annual source tests.</u> 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 **<u>hot/</u>**warm startup VOC emissions; **<u>and</u>**

~~c. Characterization of hot startup VOC emissions; and~~

<u>c</u>~~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 <u>most recent</u> ~~last such~~ tests.

AQ-16 Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B **<u>(or otherwise District approved)</u>**:

a. For NOx, Performance Specification 2.

b. For **<u>O_2</u>**~~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 Energy 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 **and current** 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), **duct burner operation time (hours),** number of startups, hours in cold startup, hours in **hot/**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 monthly~~quarterly~~, and **cumulative 12-month** ~~total~~ ~~calendar year~~ emissions of NOx, CO, PM10, 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-<u>S</u>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 **<u>169.4</u>**~~202~~ tons of NOx, **<u>51.9</u>**~~49~~ tons of VOC, ~~47 tons of SOx,~~ and **<u>60.9</u>**~~61~~ tons of PM10 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: **<u>At the end of</u>** ~~During~~ the initial commissioning period **<u>and as needed after major maintenance,</u>** the project owner shall submit a detailed record of all commissioning **<u>and tuning</u>** activities to the CPM in the **<u>Quarterly Operational Report (AQ-SC7)</u>**~~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 **<u>concentration limit</u>**

of AQ-4 above and ammonia concentration limit~~s~~ **of AQ-4 of the SCR system** shall apply coincident with the steady state operation of the SCR systems.

Verification: **At the end of** ~~During~~ the initial commissioning period **and as needed after major maintenance,** the project owner shall submit a detailed record of all commissioning **and tuning** activities to the CPM in the **Quarterly Operational Report (AQ-SC7)**~~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 **734**~~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~~ **the initial commissioning** 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.~~

a. NOx – 25.5 tons, and 193.5 pounds/hour/CTG

b. CO – 203.5 tons, and 2713.0 pounds/hour/CTG

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-SC7**) 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 **if required by the District**:

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 **hot/**warm startup VOC emissions; **and**

~~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.~~

AQ-55 This unit shall emit no more than 0.25 pounds/hour of formaldehyde (measured per California Air Resources Board Method 430) at full load.

Verification: The results of the initial compliance test (see AQ-26) and a supplemental health risk analysis (see AQ-27) shall be submitted to the District and the CPM within forty-five (45) days after testing.

AQ-56 Total emissions of Hazardous Air Pollutants or HAP (as defined in Rule 1320) from this facility shall not exceed 10 tons per year for any single HAP and 25 tons per year for any combination of HAPs, calculated on a rolling twelve month basis.

Verification: The project owner shall submit in the health risk analysis (AQ-27) the information and a rolling 12 month summary of emissions demonstrating compliance with these limits.

HRSG Duct Burner Conditions
Two (2) Individual 221.6~~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-SC7**).

AQ-30 This equipment shall be exclusively fueled with **pipeline quality** 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 Energy Commission. A summary of significant operation and maintenance events for each duct burner system shall be included in the Quarterly Operational Reports (**AQ-SC7**).

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-SC7**).

~~**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.~~

AQ-57 This equipment shall not be operated for more than 2200 hours per rolling twelve month period.

Verification: The project owner shall maintain a log of the monthly hours of operation for this equipment. This information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District and Energy Commission personnel upon request.

AQ-58 Monthly hours of operation for 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 and Energy 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-SC7**).

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 Energy 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, **and malfunction,** ammonia slip shall not exceed **5**~~10~~ ppmvd (corrected to 15% oxygen), averaged over **three**~~one~~ hour**s**.

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 Energy 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.~~

AQ-59 The project owner shall record and maintain for this equipment the following on site for a minimum of five (5) years and shall be provided to District personnel upon request.

a. Ammonia injection, in pounds per hour

b. Temperature, in degrees Fahrenheit.

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 Energy Commission personnel upon request.

Oxidation Catalyst System Conditions
[Two (2) individual oxidation catalyst systems]
[MDAQMD Application Number: 0010949 and 0010950]

AQ-60 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 oxidation catalyst system, manufacturer and design data.

AQ-61 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 oxidation catalyst system shall be included in the Quarterly Operational Reports (AQ-SC7).

AQ-62 This equipment shall be operated concurrently with the combustion turbine generator with valid District permit B008877 or B008878.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and Energy Commission 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-SC7**).

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-SC7**).

AQ-40 The drift rate shall not exceed 0.0005~~6~~ percent with a maximum circulation rate of **108,000**~~146,000~~ gallons per minute (gpm). ~~and the maximum Total Dissolved Solids shall not exceed 8190 ppm.~~ The maximum hourly PM10 emission rate ~~from this device and the evaporative condenser~~ shall not exceed

1.37~~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~~ **total dissolved solids (TDS). The average TDS shall not exceed 5050 ppm on a calendar monthly basis.** The operator shall maintain a log that contains the date and result of each blow-down water ~~quality~~ test **in TDS ppm**, 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. **The District may allow monthly testing in the future.**

Verification: A summary of the results of the weekly blow-down water ~~quality~~ tests **in TDS ppm** and the results of the mass emission rate calculations shall be submitted in the Quarterly Operational Reports (**AQ-SC7**).

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 Energy Commission upon request.

~~ONE EVAPORATIVE CONDENSER (INLET CHILLER)~~
~~[MDAQMD PERMIT NUMBER: B008883]~~

Auxiliary Boiler Conditions
[One 60 MMBtu/hr Gas Fired Auxiliary Boiler]
[MDAQMD Application Number: 0010864]

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-SC7**).

AQ-45 This equipment shall be **exclusively fueled with pipeline quality 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 Energy Commission. A summary of significant operation and maintenance events for **the auxiliary boiler** ~~each cooling tower~~ shall be included in the Quarterly Operational Reports (**AQ-SC7**).

~~**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.~~

AQ-63 This equipment is subject to the Federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and Db (Industrial-Commercial-Institutional Steam Generating Units).

Verification: The project owner shall submit auxiliary boiler specifications at least 30 days prior to purchasing auxiliary boiler for review and approval demonstrating that the auxiliary boiler meets NSPS emission limit requirements at the time of engine purchase.

AQ-64 Emissions from this equipment shall not exceed the following hourly emission limits at any firing rate, verified by fuel use and annual compliance tests (initial compliance test with respect to VOC, SOx, and PM_{10}):

a. NOx as NO_2 – 0.550 lb/hr (based on 9.0 ppmvd corrected to 3% O_2 and averaged over one hour)

b. CO – 1.853 lb/hr (based on 50 ppmvd corrected to 3% O_2 and averaged over one hour)

c. VOC as CH_4 – 0.110 lb/hr

d. SOx as SO_2 – 0.141 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)

e. PM_{10} – 0.270 lb/hr (front and back half)

Verification: The project owner shall submit the following in the Quarterly Operational Reports (AQ-SC7): 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, PM10, 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-65 This equipment shall not be operated for more than 1500 hours per rolling twelve month period.

Verification: The project owner shall maintain a log of the monthly hours of operation for this equipment. This information shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District and Energy Commission personnel upon request. A summary of operation of this equipment shall be included in the Quarterly Operational Reports (AQ-SC7).

AQ-66 **A non-resettable four-digit (9,999) hour timer shall be installed and maintained on this unit to indicate elapsed engine operating time.**

Verification: **At least 30 days prior to the installation of the engine, the project owner shall provide the District and the CPM the specification of the hour timer. A dated photograph showing cumulative hours of operation shall be included in the Quarterly Operational Reports (AQ-SC7).**

AQ-67 **The project owner shall maintain an operations log for this equipment on-site and current for a minimum of five (5) years, and said log shall be provided to District and Energy Commission personnel on request. The operations log shall include the following information at a minimum:**

a. **Total operation time (hours per month, by month);**

b. **Maximum hourly, maximum daily, monthly, and rolling 12 month emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); and,**

c. **Any permanent changes made to the equipment that would affect air pollutant emissions, and indicate when changes were made.**

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 Energy Commission personnel upon request.**

AQ-68 **The project owner shall perform the following annual compliance tests on this equipment in accordance with the MDAQMD Compliance Test Procedural Manual. The test report shall be submitted to the District and Commission no later than six weeks prior to the expiration date of this permit. The following compliance tests are required:**

a. **NOx as NO2 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 19 and 20).**

b. **CO in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Method 10).**

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

Emergency Fire Pump Conditions
[One Emergency IC Engine Driving A Fire Pump]
[MDAQMD Permit Number: E008885]

~~**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.~~

AQ-69 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. Unless otherwise noted, this equipment shall also be operated in accordance with all data and specifications submitted with the application for this permit.

Verification: A summary of significant operation and maintenance events for the fire pump engine shall be included in the Quarterly Operational Reports (AQ-SC7).

AQ-70 This unit shall only be fired on ultra-low sulfur diesel fuel, whose sulfur concentration is less than or equal to 0.0015% (15 ppm) on a weight per weight basis per CARB Diesel or equivalent requirements.

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 Energy Commission upon request.

AQ-71 A non-resettable four-digit (9,999) hour timer shall be installed and maintained on this unit to indicate elapsed engine operating time.

Verification: At least 30 days prior to the installation of the engine, the project owner shall provide the District and the CPM the specification of the hour timer. A dated photograph showing cumulative hours of operation shall be included in the Quarterly Operational Reports (AQ-SC7).

AQ-72 This unit shall be limited to emergency use defined as the pumping of water for fire suppression or protection or the pumping of water to maintain pressure in the water distribution system due to a high demand on the water supply system due to high use of water for fire suppression. In addition, this unit shall be operated no more than 50 hours per year for testing and maintenance including requirements pursuant to the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition.

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

AQ-73 The project owner shall maintain an operations log for this unit current and on-site, either at the engine location or at a on-site location, for a minimum of five (5) years, and be made available to the District staff within 5 working days from the District's request, and this log shall be provided to District, State and Federal personnel upon request. The log shall include, at a minimum, the information specified below:

a. **Date of each use and duration of each use (in hours);**

b. **Reason for use (testing & maintenance, emergency, required emission testing);**

c. **Calendar year operation in terms of fuel consumption (in gallons) and total hours; and,**

d. **Fuel sulfur concentration (the owner/operator 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 Energy Commission upon request.

AQ-74 This equipment shall exhaust through a stack at a minimum height of 30 feet.

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

AQ-75 This equipment shall not be tested during periods of startup of the combustion turbine generators.

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

AQ-76 This unit is subject to the requirements of the Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines (Title 17 CCR 93115). In the event of conflict between these conditions and the ATCM, the more stringent requirements shall govern.

Verification: The project owner shall submit the engine specifications at least 30 days prior to purchasing the engines for review and approval demonstrating that the engines meet ATCM emission limit requirements at the time of engine purchase.

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AIR QUALITY APPENDIX AIR-1
GREENHOUSE GAS EMISSIONS

Testimony of Tao Jiang, Ph.D., P.E. and David Vidaver

SUMMARY

The modified Blythe Energy Project II (BEP II) project is a proposed addition to the state's electricity system that would produce greenhouse gas (GHG) emissions while generating electricity for California consumers. The proposed BEP II will be a nominally rated 569 megawatt (MW) combined cycle facility with a maximum output of 587 MW. Its addition to the system would displace other less efficient, higher GHG-emitting generation and facilitate the integration of renewable resources. Because the project will improve the efficiency of existing system resources, the addition of BEP II would contribute to a reduction of the California GHG emissions and GHG emission rate average. The relative efficiency of the BEP II project and the system build-out of renewable resources in California would result in a net cumulative reduction of GHG emissions from new and existing fossil sources of electricity.

Electricity is produced by operation of an interconnected system of generation sources. Operation of one power plant, like the BEP II project, affects all other power plants in the interconnected system. The operation of the BEP II project would affect the overall electricity system operation and GHG emissions as follows:

- When dispatched,[5] BEP II would displace less efficient (and thus higher GHG-emitting) generation. Because the project's GHG emissions per megawatt-hour (MWh) would be lower than those of other power plants that the project would displace, the addition of BEP II would contribute to a reduction of California and overall Western Electricity Coordinating Council system GHG[6] emissions and GHG emission rate average.
- BEP II would provide dispatchable, flexible generation necessary to integrate the large amounts of intermittent renewable generation (also known as "variable energy resources") expected to meet the state's renewable portfolio standard (RPS) and GHG emission reduction targets.
- BEP II would replace some generation provided by aging, high GHG emission power plants, some that are likely to retire in order to comply with the State Water Resources Control Board's (SWRCB) policy on the use of once through cooling (OTC).
- BEP II would facilitate to some degree the replacement of high GHG emitting (e.g., out-of-state coal) electricity generation that must be phased out to meet the

[5] The entity responsible for balancing a region's electrical load and generation will "dispatch" or call on the operation of generation facilities. The "dispatch order" is generally dictated by the facility's electricity production cost, efficiency, location or contractual obligations.

[6] Fuel-use closely correlates to the efficiency of and carbon dioxide (CO_2) emissions from natural gas-fired power plants. And since CO_2 emissions from combustion dominate greenhouse gas (GHG) emissions from power plants, the terms CO_2 and GHG are used interchangeably in this section.

State’s Emissions Performance Standard (EPS; Title 20, California Code of Regulations, section 2900 et seq.) implemented by Senate Bill 1368.

CONCLUSIONS

The BEP II project, as an addition to the California electricity system, would be an efficient, new, dispatchable natural gas-fired turbine power plant that would cause GHG emissions while generating electricity for California consumers. The project’s GHG emissions per MWh would be lower than those of other power plants that the project would displace and, thus, would contribute to continued improvement of the California and overall Western Electricity Coordinating Council system greenhouse gas (GHG) emissions and GHG emission rate average. Thus, staff believes that the project would result in a cumulative overall reduction in GHG emissions from the state’s power plants, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant.

Staff notes that mandatory reporting of GHG emissions per federal government and Air Resources Board (ARB) greenhouse gas regulations would occur, and these reports will enable these agencies to gather the information needed to regulate the BEP II project in GHG trading markets, such as those that are expected to be required by the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Statutes of 2006, Chapter 488, Health and Safety Code sections 38500 et seq.). The project may be subject to additional reporting requirements and GHG reduction and trading requirements as these regulations are more fully developed and implemented.

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

The project would meet the Greenhouse Gases Emission Performance Standard (Title 20, California Code of Regulations, section 2900 et seq.) that applies to utility purchases of base load power from power plants, should the BEP II facility sell its power to a California electric utility. Any utility that enters into a contract with the BEP II project would be required to seek a finding that the project meets the EPS based on the operation of the project at that time, under a proposed Power Purchase Agreement (PPA), and any other conditions that dictate the operation of the project. The BEP II project as currently proposed meets the EPS ceiling of 0.500 metric tonnes CO_2 per megawatt-hour, with a rating of 0.373 metric tonnes CO_2 per megawatt-hour.

The BEP II project would be consistent with the conditions in the precedent decision regarding GHG emissions established by the Avenal Energy Project's Final Energy Commission Decision (not increase the overall system heat rate for natural gas plants, not interfere with generation from existing or new renewable facilities, and ensure a reduction of system-wide GHG emissions).

AIR QUALITY GHG ANALYSIS

Prepared by Tao Jiang, Ph.D., P.E.

INTRODUCTION

GHG emissions are not criteria pollutants. They are discussed in the context of cumulative impacts. The State has demonstrated a clear willingness to address global climate change though research, adaptation[7], and GHG inventory reductions. In that context, staff evaluates the GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation (see "**Project Impacts on Electricity Systems**," below) and describes the applicable GHG standards and requirements.

In December 2009, the U.S. Environmental Protection Agency (EPA) declared that greenhouse gases (GHGs) threaten the public health and welfare of the American people (the so-called "endangerment finding"). After July 1, 2011, the federal Prevention of Significant Deterioration (PSD) program requires an applicant to demonstrate that a new or modified project would meet PSD requirements, with the triggering level set at 100,000 tons per year of carbon dioxide equivalent emissions for a new project such as BEP II. Federal rules that became effective December 29, 2009 (40 CFR 98) require federal reporting of GHGs. As federal rulemaking evolves, staff at this time focuses on analyzing the ability of the project to comply with existing federal- and state-level policies and programs for GHGs.

Generation of electricity using any fossil fuel, including natural gas, can produce greenhouse gases along with the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts. For fossil fuel-fired power plants, the GHG emissions include primarily carbon dioxide, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2, which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 – often from unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG emissions are small and also are more likely to be easily

[7] While working to understand and reverse global climate change, it is prudent to also adapt to potential changes in the state's climate (for example, changing rainfall patterns).

controlled or reused or recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials.

Global warming potential is a relative measure, compared to carbon dioxide, of a compound's residence time in the atmosphere and ability to warm the planet. Mass emissions of GHGs are converted into carbon dioxide equivalent (CO_2e) metric tonnes (MT) for ease of comparison.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

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

GREENHOUSE GAS Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

APPLICABLE LAW	DESCRIPTION
Federal	
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule "tailors" GHG emissions to PSD and Title V permitting applicability criteria.
40 Code of Federal Regulations (CFR) Parts 51 and 52	A stationary source that emits more than 100,000 TPY of greenhouse gases (GHGs) is also considered to be a major stationary source subject to Prevention of Significant Determination (PSD) requirement.
40 Code of Federal Regulations (CFR) Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year.
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the California Air Resource Board (ARB) to enact standards that will reduce GHG emission to 1990 levels by 2020. Electricity production facilities will be regulated by the ARB. A cap-and-trade program is being developed to achieve approximately 20 percent of the GHG reductions expected by 2020.
California Code of Regulations, Title 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
Title 20, California Code of Regulations, Section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009	The regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 $MTCO_2$/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO_2/MWh).

GLOBAL CLIMATE CHANGE PROGRAM

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

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

The ARB adopted early action GHG reduction measures in October 2007, adopted mandatory reporting requirements and the 2020 statewide target in December 2007, and adopted a statewide scoping plan in December 2008 to identify how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. ARB staff is developing regulatory language to implement its plan and holds ongoing public workshops on key elements of the recommended GHG reduction measures, including market mechanisms. The mandatory reporting requirements are effective for electric generating facilities over 1 megawatt (MW) capacity.

Examples of strategies that the state might pursue for reducing GHG emissions in California, in addition to those recommended by the Energy Commission and the Public Utilities Commission, were identified in the California Climate Action Team’s Report to the Governor (CalEPA 2006). The scoping plan approved by ARB in December 2008 builds upon the overall climate change policies of the Climate Action Team report and shows the recommended strategies to achieve the goals for 2020 and beyond. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020 (CalEPA 2006). The scoping plan includes a 33% Renewables

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

Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade system that includes the electricity sector (ARB 2008). Mandatory compliance with cap-and-trade requirements commenced on January 1, 2012, although enforcement has been delayed until 2013. Senate Bill 2 (Simitian, Chapter 1, Statutes of 2011-12) expresses the intent to have 33 percent of California's electricity supplies by renewable sources by 2020.The scoping plan also includes a strategy to greatly expand use of combined heat and power (cogeneration) facilities.

It is possible that GHG reductions mandated by ARB will be non-uniform or disproportional across emitting sectors, in that most reductions will be based on cost-effectiveness (i.e., the greatest effect for the least cost). For example, the ARB proposes a 40% reduction in GHG from the electricity sector, even though that sector currently only produces about 25% of the state's GHG emissions. In response, in September 2008 the Energy Commission and the Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified regulation points should ARB decide that a multi-sector cap and trade system is warranted.

SB 1368,[9] enacted in 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Emission Performance Standard (EPS) of 0.500 metric tonnes CO_2 per megawatt-hour[10] (1,100 pounds CO_2/MWh). Specifically, the SB 1368 Emission Performance Standard (EPS) applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California.[11] If a project, instate or out of state, plans to sell base load electricity to California utilities, those utilities will have to demonstrate that the project meets the EPS. *Base load* units are defined as units that are expected to operate at a capacity factor higher than 60 percent. Compliance with the EPS is determined by dividing the annual average carbon dioxide emissions by the annual average net electricity production in MWh. This determination is based on capacity factors, heat rates, and corresponding emissions rates that reflect the *expected* operations of the power plant and not on full load heat rates [20 CCR §2093(a)]. At the January 12, 2012 Business Meeting, the Energy Commission opened an Order Instituting Rulemaking (12-OIR-1) to consider revisions to the EPS.

In addition to these programs, California is involved in the Western Climate Initiative, a multi-state and international effort to establish a cap-and-trade market to reduce greenhouse gas emissions in the Western United States and the Western Electricity Coordinating Council (WECC). The timelines for the implementation of this program are

[9] Public Utilities Code § 8340 et seq.

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

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

similar to those of AB 32, with full roll-out beginning in 2012. And as with AB 32, the electricity sector has been a major focus of attention.

BEP II will be required to participate in California's greenhouse gas cap-and-trade program once the program begins to operate. This cap-and-trade program is part of a broad effort by the State of California to reduce GHG emissions as required by AB32, which is being implemented by the Air Resources Board (ARB). As currently proposed, market participants such as BEP II will be required to report their GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions by purchasing allowances from the capped market and offsets from outside the AB32 program. As new participants enter the market, and the market cap is ratcheted down over time, GHG emission allowance and offset prices will increase, encouraging innovation by market participants to reduce their GHG emissions. Thus, BEP II as a GHG cap and trade participant will be consistent with California's landmark AB 32 Program, which is intended to reduce California's GHG emissions down to 1990 levels by 2020.

PROJECT CONSTRUCTION

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in short-term, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. Construction of the BEP II project would involve 16 months of activity (not including start-up or commissioning). The project owner provided a GHG emission estimate for the entirety of the construction phase. The GHG emissions estimate, presented below in **GREENHOUSE GAS Table 2**, includes the total emissions for the 16 months of construction activity in terms of CO_2-equivalent.

GREENHOUSE GAS Table 2
BEP II Estimated Potential Construction Greenhouse Gas Emissions

Construction Source	Construction-Phase GHG Emissions (Metric Tons)			
	CO_2	CH_4	N_2O	CO_2eq
Diesel combustion	4437.86	0.23	0.15	4487
Gasoline combustion	306.90	0.06	0.04	319
Construction Total	4744.76	0.29	0.18	4806

Source: Appendix 5.2-E (BEP II 2009)

PROJECT OPERATIONS

The proposed BEP II would be a nominal 569-megawatt (MW) combined-cycle electrical generating facility located within the City of Blythe, adjacent to the operational Blythe Energy Project (BEP I). The generating facility would consist of two Siemens Westinghouse SGT6-5000F combustion turbine generators (CTGs) and associated equipments. The primary sources of GHG would be the natural gas-fired combustion turbines and the auxiliary boiler. The employee and delivery traffic GHG emissions from off-site activities are negligible in comparison with the gas turbine GHG emissions.

GREENHOUSE GAS Table 3 shows what the proposed project, as permitted, could potentially emit in greenhouse gases on an annual basis. All emissions are converted to CO_2-equivalent and totaled. Electricity generation GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and also are more likely to be easily controlled or reused/recycled, but are nevertheless documented here as some of the compounds have very high relative global warming potentials.

The proposed project would be permitted, on an annual basis, to emit 1,925,384 metric tonnes of CO_2-equivalent per year if operated at its maximum permitted level. The new Blythe II facility would emit at 0.373 $MTCO_2$/MWh, which would meet the SB 1368 Greenhouse Gas Emission Performance Standard of 0.500 $MTCO_2$/MWh.

GREENHOUSE GAS Table 3
BEP II Estimated Potential Greenhouse Gas (GHG) Emissions

Emissions Source	Operational GHG Emissions ($MTCO_2$/yr) [a]	Operational GHG Emissions ($MTCO_2e$/yr) [b]
CTGs/HRSGs CO_2	1,867,938	1,867,938
CTGs/HRSGs CH_4		4,384
CTGs/HRSGs N_2O		1,097
Auxiliary Boiler CO_2	51,474	51,474
Auxiliary Boiler CH_4		80
Auxiliary Boiler N_2O		411
Total Project GHG Emissions	1,919,412	1,925,384
Estimated Annual Energy Output (MWh/yr) [c]	5,142,120	
Estimated Annualized EPS Performance ($MTCO_2$/MWh)[d]	0.373	

Sources: Table 5.2A-14 (BEP II 2009)

Notes: a. One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.

b. CH_4 and N_2O are converted into carbon dioxide equivalent (CO2e) to account for the total project GHG emissions.

c. Annualized basis uses the project owner's assumed maximum permitted operating basis.

d. Expressed as carbon dioxide, not carbon dioxide-equivalents for consistency with SB 1368.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses the cumulative effects of GHG emissions caused by both construction and operation. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation. Staff is continuing to monitor development of AB 32 Scoping Plan implementation efforts and general trends and developments affecting GHG regulation in the construction and electricity sectors.

CONSTRUCTION IMPACTS

Staff believes that the small GHG emission increases from construction activities would not be significant for several reasons. First, the period of construction will be short-term and the emissions intermittent during that period, not ongoing during the life of the project. Additionally, control measures that staff recommends to address criteria pollutant emissions, such as limiting idling times and requiring, as appropriate, equipment that meets the latest criteria pollutant emissions standards, would further minimize greenhouse gas emissions to the extent feasible. The use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of future ARB regulations to reduce GHG from construction vehicles and equipment.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

Operational impacts of the proposed project are described in detail in a later section titled "**Project Impacts on Electricity System**" since the evaluation of these effects must be done by considering the project's role(s) in the integrated electricity system. In summary, these effects include reducing the operations and greenhouse gas emissions from the older, existing power plants; potentially displacing local electricity generation; and accelerating retirements and replacements, including aging facilities and those currently using once-through cooling.

CUMUMATIVE IMPACTS

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

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

COMPLIANCE WITH LORS

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

The Energy Commission and the Public Utilities Commission provided recommendations (CPUC 2008) to ARB on how to achieve such reductions through both programmatic and regulatory approaches and identified the regulation points should ARB decide that a multi-sector cap-and-trade system is warranted. As ARB codifies improved GHG inventories and methods, it may become apparent that emission reductions from the generation sector are less cost-effective than other sectors, and that other sectors of sources can achieve reductions with relative ease and cost-effectiveness.

The project would be subject to ARB’s mandatory reporting requirements and potentially other future requirements mandating compliance with AB 32 that are being developed by ARB. How the project would comply with these ARB requirements is speculative at this time, but compliance would be mandatory. The ARB’s mandatory GHG emissions reporting requirements do not indicate whether the project, as defined, would comply with the potential GHG emissions reduction regulations being formulated under AB 32. The project may have to provide additional reports and GHG reductions, depending on the future regulations expected from ARB. Similarly, this project would be subject to federal mandatory reporting of GHG emissions.

Reporting of GHG emissions would enable the project to demonstrate consistency with the policies described above and the regulations that ARB adopts and to provide the information to demonstrate compliance with any future AB 32 requirements that could be enacted in the next few years. Since this power project would be permitted for more than a 60% annual capacity factor, the project is subject to the requirements of SB 1368 and the current Emission Performance Standard (EPS). The BEP II project’s GHG emission performance would be below the EPS limit.

PROJECT IMPACTS ON ELECTRICITY SYSTEMS (Prepared by David Vidiver)

California’s commitment to dramatically reduce greenhouse gas (GHG) emissions over the next four decades includes moving to a high-renewable/low-GHG electricity system. However, natural gas-fired power plants and the inherent GHG emissions will still be integral to the reliable operation of the electricity system for a significant share, if not all of this period. The amount of new gas-fired capacity needed to provide reliable service to the customers of the state’s investor-owned utilities, direct access providers and community choice aggregators over a ten-year planning horizon is determined in the California Public Utilities Commission’s (CPUC) Long-term Procurement Planning (LTPP) proceeding. The resulting portfolio of demand- and supply-side resources satisfies the state’s loading order, which mandates development of preferred resources (zero- and low-GHG emitting resources) in support of the state’s climate change policies before authorizing the development/financing of conventional fossil resources.

THE ROLE OF GAS-FIRED GENERATION IN A LOW-GHG ENVIRONMENT

The operation of gas-fired generation for electricity system reliability is well-established. On October 8, 2008, the Energy Commission adopted an Order Instituting Informational Proceeding (08-GHG OII-1) to solicit comments on how to assess the greenhouse gas impacts of proposed new power plants in accordance with the California Environmental Quality Act (CEQA). A report prepared as a response to the GHG OII (CEC 2009a) defines five roles that gas-fired power plants fulfill in a high-renewables, low-GHG system (CEC 2009b, pp 93 and 94):

1. Intermittent generation support
2. Local capacity requirements
3. Grid operations support
4. Extreme load and system emergency
5. General energy support.

INTERMITTENT GENERATION SUPPORT

California's renewable portfolio standard (RPS) requires that the state's energy service providers meet 33 percent of retail sales with renewable energy by 2020; meeting GHG emission reduction targets for 2050 will likely require a far higher percentage. Much of this energy will come from wind and solar resources to be developed in California.

The California Independent System Operator (CAISO) has identified an increased need for regulation and "load-following" generation as a result of the increase in these intermittent ("variable energy") renewable resources; as the output of the latter can change randomly in response to changes in wind speed, irradiance, etc.[12] Dispatchable capacity must provide "regulation," small changes in output at CAISO direction, requiring that the generator be equipped with automated generation control (AGC). "Load following" entails larger changes in output, requiring that units be increasingly economically dispatched at CAISO direction over wider ranges. This requires dispatchable generation that can start quickly when called upon to operate, ramp up and down quickly, and be capable of operating at relatively low load levels if the amount of dispatchable capacity and associated energy needed from fossil resources is to be minimized.

Gas-fired power plants are currently the only incremental resource that can provide regulation and load following in large quantities while providing other reliability services needed by the system. While dispatchable hydroelectric plants can do so, the potential for adding hydroelectric resources to the system is limited, nor can these resources be easily developed inside local reliability areas. Nuclear and solid-fueled (e.g., coal) facilities are generally only operated at full load because the fuels and technologies are

[12] Studies are available at http://www.caiso.com/informed/Pages/StakeholderProcesses/IntegrationRenewableResources.aspx

not as compatible with frequent cycling. While storage may ultimately provide significant quantities of regulation and load-following, only pumped hydro storage facilities are currently capable of doing so on a large scale; but such resources cannot be developed in large quantities in locations that simultaneously meet local reliability needs.

LOCAL CAPACITY REQUIREMENTS

The California ISO has identified numerous “local capacity areas (LCA)” and sub-areas in which threshold amounts of capacity are required to ensure reliability. Transmission constraints prevent the import of sufficient energy into these areas under high load conditions to ensure reliable service without requiring specified amounts of capacity be generating or be available to the ISO for immediate dispatch. Reliable service requires that the California ISO be able to maintain service under 1-in-10-year load conditions given the sequential failure of two major components (a large power plant and a major transmission line, for example); this requirement is imposed by the North American Electric Reliability Council (NERC). The amount of capacity needed in each of these areas (the local capacity requirement, or “LCR”) is determined annually by the ISO; the LCR study process culminates in an annual *Local Capacity Technical Analysis*.

The need for natural gas-fired capacity in LCAs stems in part from their predominantly urban nature and coastal location. The LCRs of the Greater Bay Area, Los Angeles basin, San Diego and Big Creek – Ventura LRAs are too large to be met solely with non gas-fired generation; the renewable development scenarios compiled by the CPUC for use in the 2010 LTPP proceeding indicate that only a small share of the capacity embodied in new renewable resources can be expected to reside in the large LCAs.

GRID OPERATIONS SUPPORT

System reliability requires that a share of the generation capacity be dispatchable and sufficiently flexible so as to allow aggregate output to change as rapidly as needed due to changes in demand conditions and the output of intermittent generation. Central station renewable generating technologies and customer-side-of-the-meter distributed generation not only do not possess the ability to ramp up and down or respond to dispatch instructions, but increase the amount of flexibility that the remainder of the generation fleet must have. While storage and demand response will provide an increasing share of this flexibility over time, gas-fired plants are currently the primary source of the ancillary services and voltage support that the California ISO needs to provide reliable service. New gas-fired plants are an increasingly necessary source of these services as more than 12,000 MW of aging gas-fired generation historically relied upon to provide them are likely to retire as a result of the state’s policy requiring phase-out of once-through cooling (OTC).

EXTREME LOAD AND SYSTEM EMERGENCIES SUPPORT

Natural gas-fired peaking plants fulfill the role of meeting peak demand and frequently provide black start capability, enabling them to provide the power necessary for other generating plants to restart following a widespread outage. While nuclear and hydro plants and renewable and other preferred resources can and do provide a share of the capacity – both system-wide and locally – needed to ensure reliability, natural gas-fired generation is needed to meet capacity needs during peak hours.

GENERAL ENERGY SUPPORT

The loading order indicates the resources that the state intends to rely on to meet energy needs while reducing GHG emissions. While energy efficiency, demand response programs, renewable generation, and combined heat and power are preferred resources that are to be developed before natural gas-fired generation, they are not sufficient to meet the state's future energy demand. In addition, much of the state's existing generation fleet will likely need to shut down to comply with the State Water Resource Control Board's (SWRCB's) OTC policy. Energy from natural gas-fired generation will increasingly be needed during a prolonged nuclear plant outage (for refueling for example) or during dry years, in which hydroelectric production is reduced.

QUANTIFYING THE NEED FOR GAS-FIRED GENERATION

Prior to the deregulation of the California electricity system during the 1990's, the Energy Commission's power plant siting process considered the need for power plant development. SB 110 (Chapter 581, Statutes of 1999) eliminated the requirement that projects licensed by the Energy Commission be in conformance with an integrated assessment of need that was conducted by the Energy Commission until that time. The need for new generation capacity to ensure reliable service in the IOU service territories is determined in the CPUC's biennial LTPP proceeding. This proceeding is the forum in which the state's major IOUs are authorized to finance the development of the new "least-cost, best-fit" generation (on behalf of either IOU customers or all ratepayers not served by publicly-owned utilities) needed to reliably meet electricity demand. This need, specified in terms of (a) the MW of capacity needed, (b) the desired or required operating characteristics of the resource(s) to be financed, and (c) its location, if required for local reliability, is a function of planning assumptions that reflect the state's commitment to dramatically reducing GHG emissions from the electricity sector The MW of capacity needed are driven by:

- Peak demand growth due to economic and demographic factors
- Reductions in peak demand due to committed and uncommitted energy efficiency and demand response programs
- Reserve margins (dependable[13] capacity in excess of peak demand) needed to ensure system reliability, normally assumed to be 15 percent to 17 percent of peak demand, but also including any additional dispatchable capacity needed to ensure reliability given variation in the output of intermittent renewable resources (wind, solar generation)
- Capacity to be provided by new renewable resources built/contracted with to meet the state's Renewable Portfolio Standard (RPS)

[13] The amount of capacity assumed by regulators/planning entities to be "reliably available" from a generation resource during peak hours; this may be less than the nameplate capacity of the resource.

- Capacity to be lost due to retirement, e.g., capacity expected to cease operation as a result of the State Water Resources Control Board's policy regarding the use of OTC.

The planning assumptions adopted for use in the LTPP proceeding, and thus determinant of the amount of new capacity authorized, consider both the state's "loading order" for resource development,[14] as well as targets for the development of specific types of preferred resources, including energy efficiency, demand response, and renewable generation. In other words, in authorizing the procurement/financing of dispatchable, gas-fired capacity by an IOU, the CPUC has:

- assumed that requirements/targets for preferred resources will be met, and
- found that the services required from needed capacity cannot be provided by (additional) preferred resources, or cannot be provided by them in a least-cost, best-fit manner.[15]

To date, BEP II has not successfully bid into a utility RFO for new least-cost, best fit resources. The most recent authorization for the procurement/financing of new least-cost, best-fit resources by Southern California Edison was in December, 2007, at which time the utility was authorized to procure 1,500 – 2,000 MW of dispatchable, fast-ramping resources that would facilitate the integration of intermittent renewable resources.[16] The failure of BEP II to secure a long-term PPA does not conclusively indicate that the project will not be a least-cost, best-fit choice to meet the state's goal of reducing GHG emissions from the electricity sector at some point in the future. It demonstrates that other resources – those selected in the RFO held by SCE pursuant to the procurement authorization – were lower cost providers of the services sought.

The modifications to the project whose approval is being sought by the developer would reduce the cost of providing integration services under a long-term PPA. Reducing start-up times and increasing both the ramp rates and range over which the project can efficiently operate reduce the amount of energy generated in the course of providing load-following services and capacity that provide spinning reserves. This, in turn, reduces the GHGs emitted in the provision of these services by BEP II, and increases the amount of renewable energy that can generated without threatening the reliability of the system. Should these changes result in BEP II being offered a long-term PPA by an IOU, approval of the agreement by the CPUC would constitute the agency's agreeing that the project is needed to meet the state's goal of a low-GHG electricity sector in a least-cost, best-fit manner. Should the project not receive a PPA, it is all but certain that

[14] The "loading order" calls for development of energy efficiency and demand response programs, renewable resources, and combined heat and power prior to the development of conventional fossil resources in order to meet California's energy needs.

[15] The (in)ability of generation projects to provide needed services on a least-cost, best-fit basis is determined through the RFO process that follows authorization, in which the IOUs solicit bids *cum* new projects to provide services. The costs of provision include estimated GHG emissions costs, as GHG allowance costs are included in the evaluation of fossil resources.

[16] D.07-12-052, December 20, 2007, pp. 109 – 110

BEP II will not be built[17]; even if it is built and comes on line, it will (a) displace energy from higher GHG-emission facilities, and (b) not "crowd out" renewable generation and demand-side programs, i.e., requirements/targets for the procurement of preferred resources will be unaffected.

The CPUC does not require Energy Commission certification for a generation project to participate in a utility RFO, nor does the Energy Commission require a power purchase agreement (PPA) with an IOU for a project to be considered for certification. Requiring the sequencing of these processes would not only lengthen the time needed to bring projects on line and thus threaten system reliability, it would reduce the number of projects that could compete in utility RFOs. This could lead to non-competitive solicitations, unnecessarily raising ratepayer costs without any environmental benefit. Energy Commission certification of fossil generation without a long-term PPA does not result in the construction of more fossil generation than that needed to reliably operate the system; only one merchant plant has been built since the Energy Crisis without a PPA. This project, in turn, provides capacity and ancillary services that obviates the need for the same from other, new gas-fired generation and contributes to OTC retirements.

ENERGY DISPLACEMENT AND CHANGES IN GHG EMISSIONS

Any assessment of the impact of BEP II on system-wide GHG emissions must begin with the understanding that electricity generation and demand must be in balance at all times; the energy provided by a new generation resource simultaneously displaces exactly the same amount of energy from another resource or resources. The GHG emissions produced by BEP II are thus not incremental, but are partially or totally offset by reductions in emissions from those less efficient generation resources that are displaced. As shall be demonstrated, bringing a new natural gas-fired plant on line, holding the remainder of the portfolio of available generation resources in the Western U.S. constant,[18] unambiguously reduces GHG emissions.

As electricity generated (or released from storage) must equal energy consumed at every moment in time, the energy produced by BEP II must be offset by equivalent reductions in generation elsewhere in the system.[19] It is reasonable to assume that the BEP II will be dispatched (called upon to generate electricity) whenever it is a cheaper source of energy than an alternative; i.e., that it will displace a more expensive

[17] Only one merchant facility (Inland Empire) has been constructed in California since 2003 without a long-term power purchase agreement.

[18] The California electricity system is part of the integrated Western Electricity Coordinating Council, which includes all or part of eleven states, two Canadian provinces (British Columbia and Alberta), and northern Mexico. Electricity consumed in California can be generated anywhere in this area.

[19] A new generation resource producing for on-site consumption may displace 7 percent to 8 percent more energy than it generates as transmission losses are reduced or eliminated. This does not affect the conclusions drawn herein.

resource, if not the most expensive resource that would otherwise be called upon to operate.[20]

The costs of dispatching a power plant are largely the costs of fuel, plus variable operations and maintenance (O&M) costs, with the former representing the lion's share of such costs (90 precent or more).[21] It follows that BEP II will be dispatched when it burns less fuel per MWh than the resource(s) it displaces, i.e., when it produces fewer GHG emissions. There are exceptions in theory, but not in practice:

- If a plant's variable O&M costs are so low as to offset the costs associated with its greater fuel combustion, a less efficient (higher GHG emission) plant may be dispatched first. There is no indication that BEP II's variable O&M costs are unusually low and that it would be dispatched before a more efficient facility.
- If a natural gas-fired plant's per-MMBtu fuel costs are very low, it may be less efficient (higher GHG emission) but still be dispatched first. Natural gas costs in California, however, are higher than elsewhere in the WECC.

The dispatch of BEP II will not result in the displacement of energy from renewable resources or large hydro. Most renewable resources have must-take contracts with utilities; the latter must purchase all the energy produced by these renewable generators. Even in those instances where this is not the case, (e.g., where renewable generation is participating in a spot market for energy) the variable costs associated with renewable generation are far lower than those associated with BEP II (e.g., fuel costs for wind, solar, other renewable generation technologies, and large hydro are zero or minimal); these resources can bid into spot markets for energy far below BEP II and other natural gas-fired generators. Nor would BEP II displace energy from (zero-GHG emission) nuclear generation facilities, as these resources have far lower variable operating costs as well.[22] Holding the portfolio of generation resources constant, energy from new natural gas-fired plants displaces energy from existing natural gas-fired plants.

In the longer-term, the development and operation of BEP II will facilitate the retirement of less efficient generation resources. By reducing revenue streams accruing to other

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[20] This assumption is embedded in simulation models that mimic the dispatch of the power plants that make up the WECC, as well as the (largely spreadsheet-based) models that utilities and other owners of portfolios of generation assets use to make commitment and dispatch decisions. Accordingly, any competent computer modeling of the impact of the development/dispatch of a new gas-fired power plant will yield the conclusions reached here.

[21] Other, "fixed" costs are irrelevant to the dispatch decision, as they are incurred whether or not the power plant is generating electricity.

[22] Energy from BEP II and other new natural gas-fired generation would not displace energy from coal-fired generation facilities. The price of a Btu of energy from coal is sufficiently lower than that from natural gas to more than offset the lower efficiency with which a Btu of energy from coal is converted to electricity. In other words, fuel costs per MWh are lower for coal plants than for natural gas plants. Nearly all coal-based capacity used to provide electricity to California is produced out-of-state and all will be phased out over time by the Environmental Performance Standard developed as a result of SB 1368 (Perata, Statutes of 206, Chapter 3).

resources (for the provision of both energy and capacity-related services), BEP II renders them less profitable both directly through energy and ancillary services markets and indirectly through contracts to provide capacity to ensure resource adequacy. This follows from the fixed demand for energy and ancillary services; the developers of the BEP II cannot stimulate demand for energy and other products provided by the facility, but merely serve to provide a share of the amount that is needed to meet demand and reliably operate the system. In doing so, BEP II both encourages and allows for the retirement of less efficient generation.

The long-run impact of fleet turnover can be seen from historical changes in the GHG emissions per unit of gas-fired generation in California. In 2001, more than 60 percent of gas-fired generation in California was from pre-1980 steam turbines, consuming just over 10,000 Btu per kWh. By 2010, this share had fallen to 5 percent; 63 percent of gas-fired generation was from new combined cycles with a heat rate of 7,170 Btu per kWh (CEC 2011). The output and GHG emissions of new gas-fired plants are not incremental to the system; they displace those from older plants.

While natural gas-fired plants differ in their thermal efficiency – the amount of fuel combusted, and thus GHG emissions per unit of electricity generated – very efficient gas plants are not necessarily dispatched before less efficient ones. While this would seem to contradict the assertion that output from a new plant will always displace a higher emitting one, a less efficient (e.g., at full output) plant may actually combust less fuel during a duty cycle than a plant with a lower heat rate, and thus produce fewer GHG emissions. Consider a 30-MW peaking plant with a heat rate of 10,000 Btu/kWh when operated at full output that can be moved from 0 to 50 MW and back again in a matter of minutes. Use of this plant to meet contingency needs (e.g., demand on a hot afternoon) may result in less incremental fuel combustion than a 100 MW plant with a lower heat rate at full output if the latter requires several hours and combusts large amounts of fuel to start up, must be kept on overnight in order to be available the next day and/or cannot operate at 30 MW (without a marked degradation in efficiency, and thus increases in GHG emissions).

While the fast-start Siemens SGT6-5000F turbines to be installed at BEP II would produce slightly more GHG emissions per MWh at full load than some combined cycle alternatives, they are more flexible and will be as or more efficient a provider of reliability services. Able to start up more rapidly and shut down several times a day, it will operate fewer hours to provide the same services. Able to rapidly move over a wide range of output, it will be able to operate at lower levels of output when desirable.

FLEXIBLE, DISPATCHABLE GAS-FIRED GENERATION AND THE INTEGRATION OF INTERMITTENT RENEWABLE RESOURCES

BEP II meets the criteria for an efficient dispatchable resource that facilitates the integration of intermittent renewable generation. Able to operate over a wide output range within minutes, BEP II effectively provides substantial load-following services in support of combined changes in load and output from intermittent resources as demand, wind speeds, and solar irradiance changes. Its rapid start up time and ability to cycle on and off allows it to provide load-following services without needing to be kept on line overnight producing both energy and GHG emissions hours before its energy and capacity is actually needed.

RETIREMENT OF AGING AND ONCE-THROUGH-COOLED GENERATION, AND DIVESTITURE OF HIGH GHG-EMISSION PLANTS

New resources like BEP II will be required to provide generation capacity in the likely event that a majority of facilities utilizing once-through cooling (OTC) are retired as well as to provide sufficient capacity in the event that additional aging (but not once-through cooled) plants are retired, or in order to enable such retirement. The SWRCB policy on OTC will require the retrofit, retirement, or significant curtailment of 12,319 MW of gas-fired capacity by the end of 2020.[23] **GREENHOUSE GAS Table 4** lists both the aging facilities and those in the CAISO control area that utilize OTC, including the dates by which they must comply with the SWRCB policy.

While some OTC facilities owned and operated by utilities and recently-built combined cycles may well install dry or wet cooling towers or add expensive underwater hardware to comply with OTC requirements, it is unlikely that the aging merchant plant owners will find it economic to do so. Most of these units operate at low capacity factors, suggesting a limited ability to compete in the current electricity market. Although the timing would be uncertain, new resources would out-compete aging plants and would displace the energy provided by OTC facilities and likely accelerate their retirements.

OTC facilities provide capacity to meet systemwide, zonal, and, if suitably located, local capacity needs. BEP II would provide capacity to meet system and zonal (south of Path 26) needs, but not provide local capacity, as it is not located in a transmission-constrained local capacity area.

The state’s Emissions Performance Standard (EPS), established in 2007, precludes continued investment by the California utilities in high GHG (e.g., coal-fired) generation. As a result, more than 18,000 GWh of energy from such resources will have to be replaced by 2020.

Greenhouse Gas Table 5 lists existing long-term contracts and entitlements that are expected to be phased out due to the EPS and the expected phase out dates.

[23] The policy allows for delays in compliance if doing so threatens system reliability. For example, if compliance were to require a temporary shutdown or retirement of a unit/facility and replacement capacity determined to be needed for reliability were not (yet) online, the SWRCB would allow a postponement of the compliance deadline established under the policy.

GREENHOUSE GAS Table 4
Aging and Once-Through Cooling Units: 2010 Capacity and Energy Output [a]

Plant, Unit Name	Owner	Local Reliability Area	Aging Plant?	Capacity (MW)	2010 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Diablo Canyon 1, 2	Utility	None	No	2,232	18,431	Nuclear
San Onofre 2, 3	Utility	L.A. Basin	No	2,246	13,784	Nuclear
El Centro 3, 4 [a]	Utility	None	Yes	132	61	0.344
Grayson 3-5 [a]	Utility	LADWP	Yes	108	162	0.320
Grayson 8ABC [a]	Utility	LADWP	Yes	130	3	0.888
Harbor 1,2 & 5	Utility	LADWP	No	227	172	0.508
Haynes 1, 2, 5 & 6	Utility	LADWP	Yes	1,046	957	0.567
Haynes 8 to 10	Utility	LADWP	No	560	3,436	0.375
Olive 1, 2 [a]	Utility	LADWP	Yes	110	14	0.793
Scattergood 1 to 3	Utility	LADWP	Yes	803	1,015	0.541
Utility-Owned				7,594	38,035	0.439 [c, d]
Alamitos 1 to 6	Merchant	L.A. Basin	Yes	1,970	879	0.785
Contra Costa 6, 7	Merchant	S.F. Bay	Yes	680	38	0.663
Coolwater 1-4 [a]	Merchant	None	Yes	727	15	0.573
El Segundo 4	Merchant	L.A. Basin	Yes	335	64	0.619
Encina 1 to 5	Merchant	San Diego	Yes	951	317	0.720
Etiwanda 3 & 4 [a]	Merchant	L.A. Basin	Yes	666	221	0.624
Huntington Beach 1& 2	Merchant	L.A. Basin	Yes	430	491	0.590
Mandalay 1 & 2	Merchant	Ventura	Yes	436	82	0.531
Morro Bay 3 & 4	Merchant	None	Yes	600	93	0.521
Moss Landing 6 & 7	Merchant	None	Yes	1,404	273	0.634
Moss Landing 1 &2	Merchant	None	No	1,080	3,234	0.377
Ormond Beach 1 & 2	Merchant	Ventura	Yes	1,612	117	0.564
Pittsburg 5 to 7	Merchant	S.F.Bay	Yes	1,332	58	0.663
Redondo Beach 5 to 8	Merchant	L.A. Basin	Yes	1,343	135	0.621
Merchant-Owned				13,566	6,017	0.514 [d]
Total In-State OTC				23,030	45,135	

Source: Energy Commission staff based on Quarterly Fuel and Energy Report (QFER) filings.

Notes:

a. Units are considered “aging” but are not once-through cooled.
b. Unit 7 is considered “aging” but is not once-through cooled.
c. Excludes nuclear.

GHG performance central tendency is weighted by GWh.

AVENAL PRECEDENT DECISION

The Energy Commission established a precedent decision in the Final Commission Decision for the Avenal Energy Project. This precedent decision requires all new fossil fuel-fired power plants certified by the Energy Commission to: (a) not increase the overall system heat rate for natural gas plants, (b) not interfere with generation from existing renewable facilities nor interfere with the integration of new renewable generation, and (c) take into account these factors to ensure a reduction of WECC-wide

GHG emissions and support the goals and policies of AB 32 (CEC 2009e). The proposed project, with its low heat rate, would meet these conditions.

GREENHOUSE GAS Table 5
Expiring Long-Term Contracts/Entitlements with Coal-Fired Generation through 2020

Utility	Facility	Expiration	Annual GWH
LADWP	Intermountain	through 2013	3,163
DWR	Reid Gardner	2013	1,211
SDG&E	Boardman	2013	555
SCE	Four Corners [a]	2016	4,920
Turlock ID	Boardman	2018	370
PG&E , SCE	Miscellaneous QFs	through 2019	4,086
LADWP	Navajo	2019	3,832
Total			18,137

Source: Energy Commission Staff

[a] Application for 2012 sale pending

PROPOSED CONDITIONS OF CERTIFICATION

No Conditions of Certification related to greenhouse gas emissions are proposed. The project owner would comply with mandatory ARB GHG emissions reporting regulations (California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.) and/or future GHG regulations formulated by the U. S. EPA or the ARB, such as GHG emissions cap and trade markets.

REFERENCES

ARB 2006. California Air Resource Board. AB 32 Fact Sheets, California Global Warming Solutions Act of 2006 and Timeline (www.arb.ca.gov/cc/cc.htm). September 2006.

ARB 2008. California Air Resource Board. Climate Change, Proposed Scoping Plan a Framework for Change, Pursuant to AB 32. Released October 2008, approved December 2008. http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

CalEPA 2006. California Environmental Protection Agency. Climate Action Team Report to Governor Schwarzenegger and the Legislature. March 2006.

CEC 1998. California Energy Commission. 1997 Global Climate Change, Greenhouse Gas Emissions Reduction Strategies for California, Volume 2, Staff Report. 1998.

CEC 2003. California Energy Commission. 2003 Integrated Energy Policy Report. December 2003.

CEC 2007. California Energy Commission. 2007 Integrated Energy Policy Report – Scenario Analysis of California's Electricity System. http://www.energy.ca.gov/2007_energypolicy/documents/index.html.

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CPUC 2008. California Public Utilities Commission. Final Opinion on Greenhouse Gas Regulatory Strategies. CPUC and CEC, Joint Agency proposed final opinion, publication # CEC-100-2008-007-D. Posted: September 12, 2008.

BLYTHE ENERGY PROJECT, PHASE II (02-AFC-1C)
PETITION TO AMEND COMMISSION DECISION
HAZARDOUS MATERIALS MANAGEMENT

Prepared by Alvin Greenberg, Ph.D.

INTRODUCTION AND SUMMARY OF CONCLUSIONS

On October 23, 2009, Caithness Blythe II, LLC (Caithness) filed a petition with the California Energy Commission requesting to modify the BEP II. A modification to the petition was filed on January 4, 2010. Supplement water information was filed on February 16, 2010, supplemental Transmission System Engineering (TSE) information was filed on April 23, 2010 and on October 4, 2011 supplemental information was filed for Traffic and Transportation and TSE.

As presented in the Petition to Amend (Petition) dated October 2009, the project owner is requesting permission to replace the permitted turbines with the latest technology combustion turbines available and incorporate fast-start technology. Furthermore, the project owner has proposed, in a January 4, 2010 Modification to the Petition, to not use inlet chillers on the new turbines and thus not use anhydrous ammonia at the project.

The proposed amendment does not increase or decrease the use, storage, or transportation of hazardous materials, with the exception noted below, and thus staff concludes that the amendment will not have a significant impact on hazardous materials management. However, the modification to the amendment proposes a significant revision to the project. The decision to not use anhydrous ammonia will result in reduced risk to workers and the public from the use, storage, and transportation of anhydrous ammonia.

PROJECT LOCATION AND DESCRIPTION

The BEP II is licensed as a nominally rated 520-megawatt (MW) combined-cycle facility with a maximum output of 538 MWs. The project was certified by the Energy Commission on December 14, 2005.

The Project is located within the City of Blythe, approximately five miles west of the center of the City. The BEP II site boundary is located on a 76 acre site immediately adjacent to the operational Blythe Energy Project (BEP I), owned by Blythe Energy, LLC and operated by NextEra Energy Operating Services, LLC.

ANALYSIS

The project owner has requested that Conditions of Certification **HAZ-8**, **HAZ-10**, and **HAZ-11** be eliminated in their entirety. These three conditions of certification address the safety of the anhydrous ammonia refrigeration system, fire suppression in the anhydrous ammonia refrigeration plant, and an ammonia sensor on the discharge of the anhydrous ammonia scrubber unit, all of which are part of the inlet chiller. Since the proposed new turbines will not use inlet chillers, anhydrous ammonia is longer proposed to be used on the site. Staff therefore concludes that it is no longer necessary to require these safety measures and agrees with the project owner's request to eliminate Conditions of Certification **HAZ-8, HAZ-10**, and **HAZ-11**. Aqueous ammonia continues to be proposed for use in the selective catalyst reduction system and existing conditions of certification already address the prevention of releases, containment if a release should occur, and emergency response should that be necessary.

In addition, the safety of using natural gas for pipe cleaning prior to commissioning has been reviewed and evaluated by staff. On June 28, 2010, the United States Chemical Safety and Hazard Board (CSB) issued Urgent Recommendations to the United States Occupational Safety and Health Administration (OSHA), the National Fire Protection Association (NFPA), the American Society of Mechanical Engineers (ASME), and major gas turbine manufacturers to make changes to their respective regulations, codes, and guidance to require the use of inherently safer alternatives to natural gas blows for the purposes of pipe cleaning. Recommendations were also made to the fifty states to enact legislation applicable to power plants that prohibits flammable gas blows for the purposes of pipe cleaning.

In accordance with those recommendations mentioned above regarding gas blows, staff proposes new Condition of Certification **HAZ-12** which prohibits the use of flammable gas blow for pipe cleaning at the facility either during construction or after the start of operations. All fuel gas pipe purging activities shall vent any gases to a safe location outdoors, away from workers and sources of ignition. Fuel gas pipe cleaning and purging will then be consistent with the provisions of most current versions of the National Fuel Gas Code (NFPA 56 (PS)**:** Standard for Fire and Explosion Prevention During Cleaning and Purging of Flammable Gas Piping Systems, 2012 Edition).

CONCLUSIONS AND RECOMMENDATIONS

Staff has reviewed the petition and supplemental information for potential environmental effects and consistency with applicable laws, ordinances, regulations and standards (LORS). Based on this review, staff has determined that the amendment, with staff's proposed changes, would be consistent with the LORS identified in the Energy Commission Decision. Staff proposes the deletion of Conditions of Certification **HAZ-8**, **HAZ-10**, and **HAZ-11,** and the adoption of new **HAZ-12**.

PROPOSED ELIMINATION OF CONDITIONS OF CERTIFICATION

~~Strikethrough~~ is used to indicate deleted language and <u>**underline and bold**</u> is used for new language.

~~**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).~~

~~**Verification:** 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-10** The project owner shall install an approved automatic fire suppression system in the ammonia refrigeration plant.~~

~~**Verification:** 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.~~

<u>**HAZ-12 The project owner shall not conduct or allow any fuel gas pipe cleaning activities on the site involving fuel gas pipe of four-inches or greater external diameter, either before placing the pipe into service or at any time during the lifetime of the facility, that involve "flammable gas blows" where natural (or flammable) gas is used to blow out debris from piping and then vented to atmosphere. Instead, an inherently safer method involving a non-flammable gas (e.g. air, nitrogen, steam) or mechanical pigging shall be used. The project owner shall prepare a Fuel Gas Pipe Cleaning Work Plan which shall be consistent with NFPA 56 and which shall indicate the method of cleaning to be used, what gas will be used, the source of pressurization, and whether a mechanical PIG will be used, and submit this Plan to the CBO for information, to the Riverside County Fire Department for review and comment, and to the CPM for review and approval. Exceptions to any of these provisions will be made only if no other satisfactory method is available, and then only with the approval of the CPM after review and comment from the CBO and the Riverside County Fire Department.**</u>

<u>**Verification: At least 30 days before any fuel gas pipe cleaning activities involving pipe of four-inches or greater external diameter, the project owner shall submit a copy of the Fuel Gas Pipe Cleaning Work to the CBO for information, to the Riverside County Fire Department for review and comment, and to the CPM for review and approval.**</u>

REFERENCES

BEPII 2009 – Blythe Energy Center, Phase II (02-AFC-1C). Petition to Amend. Received October 23, 2009.

BEPII 2010 - Blythe Energy Center, Phase II (02-AFC-1C). Modification to Petition to Amend. Received January 4, 2010.

BEPII 2010 - Blythe Energy Center, Phase II (02-AFC-1C). Supplement to Petition to Amend. Received February 16, 2010.

CEC 2005- California Energy Commission, Commission Decision, Blythe Energy Center, Phase II, December 14, 2005.

BLYTHE ENERGY PROJECT, PHASE II (02-AFC-1C)
PETITION TO AMEND COMMISSION DECISION
TRANSMISSION SYSTEM ENGINEERING

Prepared by Ajoy Guha, P.E. and Mark Hesters

PROJECT BACKGROUND

The Blythe Energy Project, Phase II (BEP II), owned by Caithness Blythe II, LLC (Caithness), was certified by the California Energy Commission (Energy Commission) on December 14, 2005. The BEP II was certified as a combined cycle plant consisting of two combustion turbine generator (CTG) units and one steam turbine generator (STG) unit with a total plant nominal output of 520 megawatts (MW) and would interconnect to a 500 kV substation expansion of the Western Area Power Administration’s (Western) Buck Boulevard substation. The BEP II power output would be transmitted from the new Western 500 kV substation to Southern California Edison's (SCE) existing Devers 500 kV substation by building a new 118-mile Desert Southwest Transmission Project (DSWTP) 500 kV line. The project was certified with the condition that Caithness will not begin construction of the project until the 500 kV DSWTP or an equivalent line had obtained all necessary permits.

In October 2009, Caithness submitted a petition to amend (amendment) proposing to change the type of turbines and the transmission interconnection. The amendment proposes replacing the approved Siemens Westinghouse turbines, which are no longer available, with newer fast-start Siemens turbines, increasing the power plant output from 520 MW to 570 MW. The amendment also proposes changing the BEP II transmission interconnection from the proposed Western Buck Boulevard 500 kV substation to the new proposed Keim 500 kV substation (as the first point of interconnection) through a new 2,100-foot long 500 kV generator (gen) tie line. The Keim substation would be interconnected to the new SCE Colorado River 500 kV substation (CRS) through a new 8-mile long 500 kV overhead line to deliver the BEP II power output to California Independent System Operator (ISO) grid.

SUMMARY OF CONCLUSIONS

The proposed interconnection facilities for the BEP II including the BEP II 500 kV Integration switchyard, the Keim 500 kV substation and the short 500 kV overhead gentie line to the Keim 500 kV substation and its termination would be adequate and in accordance with industry standards and good utility practices, and is acceptable to staff according to engineering Laws, Ordinances, Regulations and Standards (LORS).

The March 15, 2006 System Impact Study (SIS) and February 2, 2007 Interconnection Facilities Study (IFS) performed by SCE in coordination with the California ISO demonstrate that the addition of the 520 MW BEP II would cause significant adverse impacts on the SCE transmission system under 2009 heavy autumn system conditions with the new Devers-Colorado River (DCR) 500 kV line. The additional 50 MW associated with this amendment was the subject of additional study as described below.

According to the 2007 IFS, the reliable interconnection of the BEP II will likely require some downstream transmission upgrades. These upgrades are either within the fence line of existing substations or are needed for the interconnection of higher queue projects than the BEP II. In view of recent events, staff believes that the major reliability upgrades are not reasonably foreseeable consequences of the BEP II. The upgrades directly attributable to BEP II include a new 500 kV overhead structure and a new breaker line position at the Colorado River 500 kV substation (CRS), upgrading a wave trap within the Etiwanda generating station and installation of Special Protection Systems. The major network upgrades not attributable to BEP II include the licensed Devers-Valley #2 500 kV line and the West of Devers 230 kV upgrades. The mitigation plan, therefore, would be adequate to eliminate the adverse impacts of the BEP II and are acceptable to staff.

The February 2, 2008 California ISO BEP II 50 MW Expansion Feasibility study did not identify any additional adverse impacts beyond those found in the SIS. The study concluded that no additional reliability upgrades would be required and a Deliverability Assessment will be performed by the California ISO at a later date to determine any additional delivery upgrades.

The project owner is required to submit a revised executed Large Generator Interconnection Agreement (LGIA) and other documents as stated in Condition of Certification **TSE-5**, since the amendment states that the BEP II 500 kV gen tie line to the CRS will interconnect through the proposed new Keim 500 kV substation.

The BEP II would satisfy the Energy Commission 2005 Conditions of Certification, with the proposed changes, since construction of the DCR 500 kV line, 500 kV CRS and Devers-Valley #2 500 kV line are expected to be completed by SCE for interconnection of the BEP II and other queue projects at the CRS.

The BEP II would meet the requirements and standards of all applicable LORS upon compliance with the recommended Conditions of Certifications, as amended.

INTRODUCTION

The Transmission System Engineering (TSE) analysis examines whether or not the facilities associated with the proposed interconnection conforms to all applicable LORS required for safe and reliable electric power transmission. Staff's analysis evaluates the power plant switchyard, outlet line and termination facilities identified by the applicant. Additionally, under the CEQA, the Energy Commission must conduct an environmental review of the "whole of the action," which may include facilities not licensed by the Energy Commission (California Code of Regulations, title 14, §15378). Therefore, the Energy Commission must identify the system impacts and necessary new or modified transmission facilities downstream of the proposed interconnection that are required for interconnection and represent the “whole of the action.” The downstream network upgrade mitigation measures that will be required to maintain system reliability for the addition of the power plant, are used to identify the requirement for any additional CEQA analysis.

Energy Commission staff relies on the interconnecting authority for the analysis of impacts on the transmission grid as well as the identification and approval of required new or modified facilities downstream from the proposed interconnection that would be required as mitigation measures. The proposed BEP II would interconnect to the SCE transmission network and requires analysis by SCE and approval of the California ISO.

SCE’S ROLE

SCE is responsible for ensuring electric system reliability in the SCE system for addition of the proposed generating plant. SCE will provide the analysis and reports in their System Impact and Facilities studies, and their approval for the facilities and changes required in the SCE system for addition of the proposed transmission modifications.

CALIFORNIA ISO’S ROLE

The California ISO is responsible for ensuring electric system reliability for all participating transmission owners and is also responsible for developing the standards necessary to achieve system reliability. The California ISO is responsible for completing the interconnection studies of the SCE system to ensure adequacy of the proposed transmission interconnection. The California ISO will determine the reliability and delivery impacts of the proposed transmission modifications on the SCE transmission system in accordance with all applicable reliability criteria. According to the California ISO Tariffs, the California ISO will determine the “Need” for transmission additions or upgrades downstream from the interconnection point to insure reliability of the transmission grid. The California ISO will, therefore, review the SIS performed by SCE and/or any third party, provide their analysis, conclusions and recommendations. On satisfactory completion of the SCE IFS and in accordance with the Large Generator Interconnection Procedures, as in the California ISO Tariff, the California ISO would subsequently perform a deliverability assessment to determine whether additional delivery upgrades are needed for the project to be fully deliverable before proceeding to execute a LGIA between the California ISO and the project owner. The California ISO may also provide written and verbal testimony on their findings at the Energy Commission hearings, if necessary.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

- California Public Utilities Commission (CPUC) General Order 95 (GO-95), “Rules for Overhead Electric Line Construction,” formulates uniform requirements for construction of overhead lines. Compliance with this order ensures adequate service and safety to persons engaged in the construction, maintenance and operation or use of overhead electric lines and to the public in general.

- California Public Utilities Commission (CPUC) General Order 128 (GO-128), “Rules for Construction of Underground Electric Supply and Communications Systems,” formulates uniform requirements and minimum standards to be used for underground supply systems to ensure adequate service and safety to persons engaged in the construction, maintenance and operation or use of underground electric lines and to the public in general.
- The National Electric Safety Code, 2007 provides electrical, mechanical, civil and structural requirements for overhead electric line construction and operation.
- The North American Electric Reliability Corporation (NERC) Reliability Standards define the plans, policies & procedures, methodologies & system models, coordination & responsibilities, and performance criteria for reliable planning, control and operation of the North American Bulk Electric System (BES) over broad spectrum of system conditions and following a wide range of probable disturbances. The Standards cover all aspects of an interconnected BES such as: Transmission system planning & operation, consistent data (steady-state and dynamic) for modeling and simulation, facility ratings methodology and connections, balancing real power, resources & load demand, procedures for voltage control & reactive power, system protection, control, communications & security, nuclear plant interface coordination, emergency operation planning and system restoration plans. The transmission planning standards stipulate periodic system simulations and associated assessments over a planning horizon by the planning authority and transmission planner to ensure that reliable systems are planned with sufficient lead time to meet the system performance requirements and continue to be modified or upgraded as necessary for operating the network reliably to supply projected customer demands and firm transmission services under normal and forced or maintenance outage system conditions.
- For an interconnected bulk electric system, the Table I in the NERC Transmission Planning Standards specifies the system performance requirements during normal system conditions with all facilities in service (pre-contingency) and normal operating procedures in effect under Category A, and during probable and rationale contingencies of a single BES element under Category B and two or more (multiple) BES elements under Category C. The performance limits or impacts for the above Categories A-C are specified for a reliable system as to remain stable, and within applicable normal and emergency facility thermal ratings and system voltage limits as determined and applied by the transmission owner according to the NERC Facility Ratings Standards. Specified system performance limits may vary from no loss of load demand or curtailed generation/firm transfers for insignificant adverse impacts (for Categories A & B) to planned/controlled loss of load demand or curtailed generation/firm transfers (for Category C) without any cascading outages. However, during major extreme disturbances such as loss of multiple 500 kV lines on a common right-of-way with cascading outages or multiple generators with loss of a major load center as stated under Category D in the Table I, some of the interconnected systems may become unstable resulting in widespread black out in islanded areas. The standards require the planning authority to

evaluate the risks and consequences for such catastrophic events, and be prepared according to the NERC Emergency Operation Planning Standard and/or to restore the system to normal according to the NERC standard for System Restoration Plans (NERC 2005-10).

- The Western Electric Coordinating Council (WECC) Regional System Performance Criteria is similar to the system performance limits as defined in NERC transmission planning standards. The WECC performance criteria incorporate the Table I of the NERC transmission planning standards and in addition include the WECC Disturbance-Performance Table W-1 which provides standards for transient voltage and frequency limits, and post-transient system voltage variation. Certain aspects of the WECC performance criteria are either more stringent or specific than the NERC standards such as inclusion of contingency event frequencies and additional Category C & D contingencies. Adequate reactive power resources planning criteria for transfer path ratings and post-transient voltage stability are also included. For any past disturbance that actually resulted in cascading outages in the interconnected system, the WECC performance criteria require remedial action so that future occurrences of such event would not result in cascading (WECC 2008).
- California ISO Planning Standards also provide standards and guidelines to ensure the adequacy, security and reliability in the planning of the California ISO grid transmission facilities. The Standards incorporate the current NERC Reliability Planning Standards and WECC Regional System Performance Criteria. However, the California ISO Standards are more stringent or specific than the NERC standards and WECC performance criteria. The Standards include additional Category B disturbance elements and criteria for existing nuclear plant unit’s control. The Standards also address new transmission vs. involuntary load interruptions and San Francisco greater bay area generation outage criteria for conducting grid planning for the bay area. The California ISO Standards apply to the electric systems of all participating transmission owners interconnecting to the California ISO controlled grid. They also apply when there are any impacts to the California ISO grid due to facilities interconnecting to adjacent controlled grids not operated by the California ISO (California ISO 2002a).
- California ISO/FERC Electric Tariff provides rules, procedures and guidelines for construction of all transmission additions/upgrades (projects) within the California ISO controlled grid. The California ISO determines the “Need” for the proposed project where it will promote economic efficiency or maintain system reliability. The California ISO also determines the Cost Responsibility of the proposed project and provides an Operational Review of all facilities that are to be connected to the California ISO grid. The Tariff specifies the required LGIP and LGIA to be followed for any large generator interconnection to the California ISO controlled grid (California ISO 2010a).

PROJECT DESCRIPTION

The BEP II would be located in the Blythe area about 2,000 feet southwest of the Western Buck Boulevard 161/230 kV substation. The BEP II would consist of two CTGs, each rated 285 MVA, 16.5 kV and one 405 MVA, 19 kV STG unit, for a total nominal net output of 570 MW. Each of the CTG units would be connected through a segregated bus duct and a 16 kV breaker to the low voltage terminal of a dedicated 171/228/285 MVA, 16/500 kV generator step-up (GSU) transformer. The STG unit would be connected through a segregated bus duct to the low voltage terminal of a dedicated 243/324/405 MVA, 19/500 kV GSU transformer (BEP II 2009a: Petition for Amendment).

SWITCHYARDS AND INTERCONNECTION FACILITIES

The BEP II 500 kV Integration Switchyard would have a 4,000-ampere single bus arrangement. The 500 kV high voltage terminals of each GSU transformer would be connected to the switchyard 500 kV bus by short overhead conductors through a 3,000-ampere 500 kV circuit breaker and a disconnect switch. The BEP II 500 kV switchyard would be connected to the proposed Keim 500 kV substation (as a first point of Interconnection) by building a new short 2,100-foot long single circuit 500 kV gen tie line with 2-2156 Kcmil steel-reinforced aluminum conductors (ACSR) on 90 to 140-foot high tubular steel poles. The short 500 kV overhead line on one end would be connected to the BEP II switchyard 500 kV bus through a 3,000-ampere 500 kV circuit breaker and two associated disconnect switches. The other end of the 500 kV short line would be connected to the Keim substation ring bus as a double breaker line position. During interconnection of the BEP II, the proposed Keim 500 kV substation would be built as a ring bus arrangement with associated three 500 kV breakers for three 500 kV line positions, each breaker with two associated disconnect switches, and with a future provision for a fourth 500 kV breaker (for connecting in future to a 500/230 kV step-down transformer and 230 kV buses with breakers for additional 230 kV transmission outlets). The Keim 500 kV substation would be finally interconnected to the new SCE 500 kV CRS (previously called the Midpoint substation) through a new 8-mile long 500 kV transmission line (BEP II 2010a: Data Response set #1; BEP II 2010e: Data Response set #2; BEP II 2011a: Data Response set #3).

The BEP II 500 kV switchyard and the short 2,100-foot long 500 kV gen line would be built by Caithness. The Keim 500 KV substation and the new 8-mile long 500 kV line to the CRS would be built by the DSWTP 500 kV line participants. SCE would build the 500 kV CRS where the DPV1 and DCR lines would be looped in, and provide a line breaker position and transmission outlet for the 500 kV line to the Keim substation.

The proposed interconnection facilities for the BEP II including the BEP II 500 kV Integration switchyard, the Keim 500 kV substation, the short 500 kV overhead gen tie line to the Keim 500 kV substation and its termination would be adequate and in accordance with industry standards and good utility practices, and is acceptable to staff according to engineering LORS. Proposed Conditions of Certifications **TSE-1** to **TSE-8**, as amended, insure that the proposed facilities are designed, built and operated in accordance with good utility practices and applicable LORS.

TRANSMISSION SYSTEM IMPACT ANALYSIS

For the interconnection of a proposed generating unit or transmission facility to the grid, the interconnecting utility and the control area operator are responsible for ensuring grid reliability. For the BEP II, SCE and California ISO are responsible for ensuring grid reliability. In accordance with the FERC/California ISO/Utility Tariffs, SIS and IFS are conducted to determine the preferred and alternate interconnection methods to the grid, the downstream transmission system impacts and the mitigation measures needed to ensure system conformance with performance levels required by the utility reliability criteria, NERC planning standards, WECC reliability criteria, and California ISO reliability criteria. Staff relies on the studies and any review conducted by the responsible agencies to determine the effect of the project on the transmission grid and to identify any necessary downstream facilities or project impacts required to bring the transmission network into compliance with applicable reliability standards (NERC2006, WECC 2006, California ISO 2002a and 2007a).

The SIS and IFS analyze the grid with and without the proposed project under conditions specified in the planning standards and reliability criteria. The standards and criteria define the assumptions used in the study and establish the thresholds by which grid reliability is determined. The studies must analyze the impact of the project for the proposed first year of operation and thus are based on a forecast of loads, generation and transmission. Load forecasts are developed by the interconnected utility, which would be SCE in this case. Generation and transmission forecasts are established by an interconnection queue. The studies are focused on thermal overloads, voltage deviations, system stability (excessive oscillations in generators and transmission system, voltage collapse, loss of loads or cascading outages), and short circuit duties. SCE completed the SIS in March, 2006 and the IFS in February, 2007.

If the studies show that the interconnection of the project causes the grid to be out of compliance with reliability standards, the study will then identify mitigation alternatives or ways in which the grid could be brought into compliance with reliability standards. If the interconnecting utility determines that the only feasible mitigation includes transmission modifications or additions which require CEQA review as part of the “whole of the action,” the Energy Commission must analyze those modifications or additions according to CEQA requirements.

SCOPE OF SYSTEM IMPACT STUDY, INTERCONNECTION FACILITIES STUDY AND FEASIBILITY STUDY

The March 15, 2006 SIS was prepared by SCE to analyze the impacts of the 520 MW BEP II (California ISO serial interconnection queue #16, dated 3-11-2003) on the SCE transmission system. The BEP II would be located in the Blythe, California and interconnect to a new SCE 500 kV CRS. The study was performed with 2009 heavy autumn load forecast and with maximum autumn East of the River (EOR) and West of the River (WOR) flows. The study included the BEP II and all serial queue generation projects with higher queue positions than the BEPII. Southern California generation and critical seasonal power flows in WECC paths were maintained within limits. In addition, the generation in the Los Angeles basin was offset to fully stress the existing Devers-Palo Verde #1 (DPV1) 500 kV line. The impacts were analyzed with and without the new Devers-Colorado River (Harquahala) 500 kV line. Since the studies were completed, the DCR project evolved into the Colorado River-Devers-Valley 500 kV project and has received all the necessary permits. The DPV1 and DCR lines were considered connected to 500 kV CRS by looping in the CRS 500 kV bus. The base cases included planned California ISO approved transmission upgrades that would be operational by 2009. The study scenarios include i) 2009 heavy autumn pre and post-project base cases with and without the DCR in service and natural flow, and ii) 2009 heavy autumn pre and post-project base cases with and without the DCR in service and increased line compensation on DPV1 and DCR as applicable. The California ISO subsequently reviewed the SIS and in their letter of May 17, 2006 requested SCE to proceed with the IFS (BEP II 2010b: March 15, 2006 System Impact Study report and May 17, 2006 California ISO letter).

The February 2, 2007 IFS was prepared by SCE in coordination with the California ISO. The IFS addressed the SIS performed with 2009 heavy autumn pre and post-project cases with DCR and natural flow, and identified the interconnection facilities requirements and downstream transmission facilities upgrade requirements including their good faith cost estimates for reliable interconnection of the BEP II to the SCE system (BEP II 2010c: February 2, 2007 SCE Interconnection Facilities study report).

The February 27, 2008 BEP II Expansion Feasibility Study was performed by the California ISO and SCE to analyze the impacts on the SCE transmission system, since the total nominal output of the BEP II would be amended from 520 MW to 570 MW, an increase of 50 MW generation output to the SCE system (Interconnection serial queue #219 dated 5-23-2007). The study was performed under two critical SCE system conditions:

- A 2013 heavy summer base case with a 1-in-10 year load forecast, 28,114 MW in SCE area and with DCR. The case was derived from SCE’s 2007 annual transmission planning assessment.
- A 2013 light spring base case at about 65 percent of the heavy summer peak load level (18,322 MW in SCE area) with DCR.

The study included all active queued generation projects in the SCE study area (total 14,082 MW including the BEP II expansion project) ahead of the BEP II expansion project regardless of their in-service dates. The system load condition was based on the latest in-service dates of all higher queued projects. This methodology serves to identify all needed network upgrades and to facilitate assignment of the project cost responsibility (BEP II 2010d: BEP II 50 MW Expansion Feasibility study report).

Power Flow Study Results and Mitigation

The March 7, 2006 SIS and the February 2, 2007 IFS analyzed the SCE system under 2009 heavy autumn system conditions for the following four different alternatives:

Alternative 1: Pre and post-project cases with DCR in service and natural flow.

Alternative 2: Pre and post-project cases with DCR in service and increased line compensation on both DPV1 and DCR.

Alternative 3: Pre and post-project cases without DCR in service and natural flow.

Alternative 4: Pre and post-project cases without DCR in service and increased line compensation on both DPV1 and DCR.

The California ISO subsequently reviewed the SIS and in their letter of May 17, 2006 requested SCE to proceed with the IFS. Alternatives 3 and 4 analyses were considered informational only. Since the modified DCR was approved by the California ISO board and moving ahead, and in consideration of the Blythe II position in the Interconnection queue, the Alternative 1 analysis with the pre and post project cases with the DCR was considered the appropriate basis for determining incremental impacts and interconnection requirements for the BEP II, while Alternative 2 analysis may be addressed at a later date. The power flow study results with DCR line are shown in Tables 1-3 of the SIS (BEP II 2010b: March 15, 2006 SCE System Impact study report).

The steady state power flow analysis in the SIS demonstrates that the addition of the 520 MW BEPII would cause significant overloads on the SCE transmission system. The addition of the BEP II would trigger Category B (N-1) contingency overloads on four 230 kV lines and on a 500 kV line, and new Category C (N-2) overload on a 230 kV line. The addition of the BEP II would also aggravate one Category A (N-0) normal pre-project overload on a 500 kV line, Category B (N-1) contingency pre-project overloads on three 500 kV lines, two 500/230 kV transformer banks and a 230 kV line, and Category C pre-project overload on a 500 kV line (BEP II 2010c: February 2, 2007 SCE Interconnection Facilities study report)..

The following is the summary of the new and aggravated pre-project overloaded lines:

1. Base case Overload:
    a. Category A: Aggravates pre-project overload on the Devers-Valley 500 kV line.
2. Contingency Overloads:
    a. Aggravates pre-project overloads on the following facilities under Category B (N-1) condtions:
        i) DCR line.
        ii) El Dorado-Moenkopi 500 kV line

iii) Devers 500/230 kV substation transformer Bank #1 and Bank #2

iv) Mira Loma-Vista 230 kV line

v) Devers-Valley 500 kV line.

b. Causes new overloads on the following lines under Category B (N-1) conditions:

i) San Bernardino-Vista 230 kV line

ii) Devers-Vista #1 and #2 230 kV lines

iii) Etiwanda-Vista 230 kV line.

iv) Devers-Valley 500 kV line.

MITIGATION PLAN:

The February 2, 2007 IFS addressed the scope of work including the mitigation of the identified overloaded lines comprehensively in two parts (BEP II 2010c: February 2, 2007 SCE Interconnection Facilities study report).

Case A Facilities: All Facilities required exclusively by the project on the SCE system including telecommunication facilities:

1) Installation of a 500 kV structure with overhead fixtures (insulators, conductors etc.) inside the 500 kV CRS fence line for connecting the 500 kV gen tie line.

2) Installation of a new 500 kV line breaker position (switch bay) to terminate the Gen tie line to the CRS 500 kV bus.

3) At Etiwanda Gen Station: Replace the 2,000 A rated wave trap on the Vista 230 kV line position with a new 3,000 A rated wave trap.

4) Installation of a SPS (Special Protection System) at Etiwanda Gen Station.

5) Installation of a SPS at San Bernardino Gen Station.

6) Telecommunication facilities as required.

7) Power system control facilities as required

Case B Facilities:

These facilities are required to remedy the overloads caused by the higher queue projects than the BEP II. According to the IFS in the event any of the earlier projects withdraws their Application, the BEP II may be responsible for any or all of these additional facilities. These facilities are not considered reasonably foreseeable consequences of the BEP II project.

The mitigation measures include:

1) Looping the DPV1 and DCR lines into the CRS.

2) Devers-Valley #1 500 kV line: Relocation of the Valley substation line termination from the existing GIS building to a new outdoor line position.

3) Devers- Valley #2 500 kV line: Building a new 42-mile 500 kV line with 2-2156 kcmil ACSR conductors.

4) 500 kV CRS: Installation of a new 500 kV Interconnection facilities to loop the DPV1 and DCR lines and provide space for an additional line position to terminate the future BEP II-CRS gen tie line, and installation of a SPS.

5) Devers substation: Upgrading the Valley #1 500 kV line position to 4,000 A rating and installation of a new 4,000 A line position to terminate the new Valley #2 500 kV line, and installation of a SPS.

6) Vista substation: Replacement of line drops on the Mira Loma 230 kV line position with higher ampere rating.

7) DPV1 (within California) series capacitors: Upgrading to 4,000/5,400 A ratings.

8) DCR (within California) series capacitors: Upgrading to 4,000/5,400 A ratings.

9) West of Devers 230 kV Upgrades: The work requires reconductoring of the Devers-Vista #1 & #2 230 kV lines, Devers-San Bernardino #1 & #2 230 kV lines with 2-1033 kcmil ACSR conductors and upgrading terminal equipment at Devers, Vista and San Bernardino 230 kV substations as necessary. Replacement and upgrades of 230 kV circuit breakers at several substations are also involved.

10) Telecommunications requirements to support the line protection relays after looping the DPV1 & DCR lines into the 500 kV CRS, and interface terminal equipment at the Devers and CRS substations to support the SPS.

COMMENTS ON THE MITIGATION PLAN:

The above mitigation measures were derived in the IFS in 2007. The situation has changed and there have been new developments. SCE has received the permits from the California Public Utilities Commission (CPUC), Bureau of Land Management (BLM) and others to build the California portion of the new DCR line (Devers-CRS #2 500 kV line), the 500 kV CRS and Devers-Valley #2 500 kV line. SCE has recently commenced construction of the DCR line. Staff expects the construction of the DCR line, 500 kV CRS will be completed by the year 2013. In addition, SCE opted for completion/construction of the new Devers-Valley #2 500 kV line which would accommodate additional power flow through the new DCR line and also relieve some of the overloads on the West of Devers 230 kV lines. Therefore, implementation of the West of Devers upgrade project (currently under SCE's "Planning and Siting" status) is not necessarily applicable at this stage for interconnection of the BEP II and higher queue projects. However the West of Devers upgrades may be required to provide deliverability for other generators in the California ISO queue.

Staff believes that in view of these current developments it is reasonable to conclude that the BEP II should not be responsible for any of the above Case B facilities, but would remain responsible for Case A facilities only. The mitigation plan, therefore, would be adequate to eliminate the adverse impacts of the BEP II and is acceptable to staff.

Short Circuit Study Results A and Substation Evaluation

Three line-to-ground (3 LG) and single line-to-ground (SLG) faults were simulated with and without the BEP II to determine if there are any overstressed circuit breakers in SCE substations in the project vicinity caused by the addition of the project. The short circuit duty analysis included all higher queue projects and the related transmission upgrades. The short circuit study results in the SIS present the impact for the addition of the BEP II only (BEP II 2010b: March 15, 2006 SCE System Impact study report).

The substation evaluation as stated in the IFS found all circuit breakers (CB) adequate under Case A scope of work. Under Case B scope of work, replacing eight CBs and upgrading two CBs at the Devers substation, and upgrading two CBs at the Vincent substation are required. Since all these CBs upgrades were included in the West of Devers upgrade, the upgrades are no longer applicable to the BEP II and other higher queue projects (BEP II 2010c: February 2, 2007 SCE Interconnection Facilities study report).

Transient Stability Study Results

Transient stability analysis is performed to determine whether the transmission system would remain stable with the addition of the BEP II. The analysis was performed in the SIS with the 2009 heavy autumn base case with simulated faults under selected critical single and double contingencies. The analysis could not identify any transient stability violations caused by the BEP II (BEP II 2010b: March 15, 2006 SCE System Impact study report).

Post-transient Voltage Analysis Results

The power flow study in the SIS did not find any voltage deviations beyond stipulated limits in the SCE system under contingency conditions. As such no post-transient voltage study was necessary (BEP II 2010b: March 15, 2006 SCE System Impact study report).

BEP II Expansion Feasibility Study

The February 27, 2008 BEP II 50 MW Expansion Feasibility study was performed to analyze the impacts on the SCE system for amended increase in total nominal generation output from 520 MW to 570 MW. The study was performed by the California ISO and SCE with 2013 heavy summer and 2013 light spring base cases. The power flow, transient stability and post-transient voltage analyses did not identify any adverse impacts beyond those previously identified in the initial March 15, 2006 SIS with BEP II 520 MW nominal output. Consequently, no additional upgrades would be required for the 50 MW expansion. However, the study concludes that a Deliverability Assessment will be performed by the California ISO at a later date to determine whether any additional delivery upgrades are needed for the project to be fully deliverable to the grid (BEP II 2010d: BEP II 50 MW Expansion Feasibility study report).

CONFORMANCE WITH LORS AND CEQA REVIEW

The proposed interconnection facilities for the BEP II including the BEP II 500 kV Integration switchyard, the Keim 500 kV substation, the short 500 kV overhead gen tie line to the Keim 500 kV substation and its termination would be adequate and in accordance with industry standards and good utility practices, and is acceptable to staff according to engineering LORS.

The March 15, 2006 SIS and the February 2, 2007 IFS demonstrate that the addition of the 520 MW BEP II would cause the SCE transmission system to be out of compliance with reliability standards. The major reliability network upgrades are not attributable to the BEP II and instead would be required whether or not the BEP II would ever be constructed. However, the reliable interconnection of BEP II would require some upgrades/modifications within the fence line of the existing or planned substations. The mitigation plan would, therefore, be adequate to eliminate the adverse impacts of the BEP II and are acceptable to staff.

The February 2, 2008 BEP II 50 MW Expansion Feasibility study did not identify any adverse impacts beyond those identified in the SIS. Consequently no additional system upgrades would be required. However, a Deliverability Assessment will be performed by the California ISO at a later date to determine whether any additional delivery upgrades are needed for the project to be fully deliverable to the grid.

The applicant is required to submit a revised executed LGIA and other documents as stated in Condition of Certification TSE*,* since in the amendment the Blythe II 500 kV gen tie line to the CRS will interconnect through the proposed new 500 kV Keim substation.

The BEP II would meet the requirements and standards of all applicable LORS upon satisfactory compliance of the Conditions of Certifications.

RESPONSE TO AGENCY AND PUBLIC COMMENTS

No agency or public comments related to TSE discipline have been received.

CONCLUSIONS AND RECOMMENDATIONS

1. The proposed interconnection facilities for the BEP II including the BEP II 500 kV integration switchyard, the Keim 500 kV substation, the 500 kV overhead gen tie line to the Keim 500 kV substation and its termination would be adequate and in accordance with industry standards and good utility practices, and is acceptable to staff according to engineering LORS.
2. The March 15, 2006 SIS and February 2, 2007 IFS performed by SCE in coordination with the California ISO demonstrate that the addition of the 520 MW BEP II would trigger new Contingency (N-1) overloads and also aggravate

normal (N-0) and Contingency (N-1 & N-2) pre-project overloads on the SCE transmission system under 2009 heavy autumn system conditions with the new Devers-Colorado River 500 kV line.

3. According to the 2007 IFS the reliable interconnection of the BEP II will likely require some downstream transmission upgrades, these upgrades are either within fence line of existing substations or are needed for the interconnection of higher queue projects than the BEP II. In view of recent developments staff believes that the major reliability upgrades are not a reasonably foreseeable consequences of the BEP II. The upgrades directly attributable to BEP II include a new 500 kV overhead structure and a new breaker line position at the 500 kV Colorado River substation, upgrading a wave trap within the Etiwanda generating station and installation of two Special Protection Systems. The major network upgrades not attributable to BEP II include the licensed Devers-Valley #2 500 kV line and the West of Devers 230 kV upgrades. The mitigation plan, therefore, would be adequate to eliminate the adverse impacts of the BEP II and are acceptable to staff.
4. The February 2, 2008 California ISO BEP II 50 MW Expansion Feasibility study did not identify any additional adverse impacts beyond those identified in the SIS. Consequently no additional reliability upgrades would be required. However, a Deliverability Assessment will be performed by the California ISO at a later date to determine whether any additional delivery upgrades are needed for the project to be fully deliverable to the grid.
5. The project owner is required to submit a revised executed LGIA and other documents as stated in Condition of Certification **TSE-5**, since in the amendment the Blythe II 500 kV gen tie line to the CRS will interconnect through the proposed new 500 kV Keim substation.
6. The BEP II would satisfy the Energy Commission 2005 Conditions of Certifications, since construction of the DCR 500 kV line, 500 kV CRS and Devers-Valley #2 500 kV line are expected to be completed by SCE for interconnection of the BEP II and other queue projects at the CRS.
7. The BEP II would meet the requirements and standards of all applicable LORS upon compliance with the recommended Conditions of Certifications.

RECOMMENDATIONS

If the Energy Commission approves the project, staff recommends the following Conditions of Certification to ensure system reliability and conformance with LORS.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

Below is a list of the revised TSE Conditions of Certification, which were originally contained in the Decision for BEP II (CEC 2005a). ~~Strikethrough~~ is used to indicate deleted language and **underline and bold** is used for new language.

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, **generator** ~~and transmission~~ tie line **and its termination**.

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~~ a Master Drawing List, and a Master Specifications List to the CBO and to the CPM. The schedule shall contain a description and list of proposed submittal packages for design, calculations, and specifications for major structures and equipment (see a list of major equipment in **Table 1: Major Equipment List** ~~(~~below). Additions and deletions shall be made to the table only with CPM and CBO approval. The project owner shall provide schedule updates in the Monthly Compliance Report.

Table 1: Major Equipment List
Breakers
Step-up Transformer
Switchyard
Busses
Surge Arrestors
Disconnects and Wave-traps
Take off facilities
Electrical Control Building
Switchyard Control Building
Transmission Pole/Tower
Insulators and Conductors
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.

Verification: At least 30 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of rough grading ~~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 **Integration** 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~~ **transmission facilities** will conform to all applicable LORS, ~~including~~ **and** 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.

Once approved, the project owner shall inform the CPM and CBO of any anticipated changes to the design, and shall submit a detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change to the CPM and CBO for review and approval. ~~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~~ **California ISO and/or SCE** 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~~ **SCE** 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.~~

i) The Special Protection System (SPS) sequencing and timing, if applicable;

ii) A letter stating that the mitigation measures or projects selected by the transmission owner for each reliability criteria violation, for which the project is responsible, are acceptable;

iii) A Deliverability Assessment report from the California ISO and/or SCE according to the California ISO Tariff;

iv) A letter from SCE and/or the California ISO confirming that the Blythe II 500 kV generation tie line to the new SCE 500 kV Colorado River Substation will interconnect through the proposed new 500 kV Keim substation;

v) A copy of the executed LGIA signed by the California ISO and the project owner which must include the new proposed Keim 500 kV substation as an interconnection facility (in Appendix A of the LGIA) in addition to the new Blythe II 500 kV integration switchyard and the Blythe II 500 kV generator tie line to the SCE 500 kV Colorado River substation, and

vi) A schedule for commercial operation of the new Keim 500 kV substation prior to completing construction of the Blythe II 500 kV generator tie line.

Verification: At least ~~90~~ **60** 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 National Electric Safety Code (NESC), Title 8 **of the California Code of Regulations**, Articles 35, 36 and 37 of the “*High Voltage Electric Safety Orders*”, **California ISO Standards, National Electric Code (**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”[24] 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 **National Electric Safety code (**NESC**)**, Title 8 of the California Code of Regulations, Articles 35, 36 and 37 of the “*High Voltage Electric Safety Orders*”, **California ISO Standards,** ~~IEEE grounding standards,~~ **National Electric Code (**NEC**)** ~~applicable interconnection standards~~, and related industry standards.

[1] Worst-case conditions for the foundations would include for instance, a dead-end or angle pole.

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.~~

e) The Special Protection System (SPS) sequencing and timing if applicable shall be provided concurrently to the CPM.

f) A letter stating that the mitigation measures or projects selected by the transmission owner for each reliability criteria violation, for which the project is responsible, are acceptable,

g) A Deliverability Assessment report from the California ISO and/SCE under the California ISO Tariff.

h) A letter from SCE and/or the California ISO confirming that the Blythe II generation overhead 500 kV tie line to the new SCE 500 kV CRS will interconnect through the proposed new Kiem 500 kV substation.

i) A copy of the executed LGIA signed by the California ISO and the project owner which must include the new Keim 500 kV substation as an interconnection facility (in the Appendix A of the LGIA) between the new Blythe II 500 kV integration switchyard and the 500 kV Colorado River substation, and

j) A schedule for commercial operation of the new Keim 500 kV substation prior to completing construction of the 500 kV generation tie line.

Prior to the construction of or start of modification of transmission facilities, the project owner shall inform the CBO and the CPM of any anticipated changes to the design that are different from the design previously submitted and approved and shall submit a detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change to the CPM and CBO for review and approval.

~~**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 notice~~s~~ to the ~~Western Area Power Administration, Desert Southwest Region (Western, DSR) and the~~ California Independent System Operator (~~Cal-~~ California 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-~~ California ISO a letter stating the proposed date of synchronization; and

2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the ~~Western, DSR and~~ ~~Cal-~~ California ISO Outage Coordination Department.

Verification: The project owner shall provide copies of the ~~Western,~~ ~~DSR and Cal-~~ California ISO letter~~s~~ to the CPM when they are sent to the ~~Western, DSR and~~ ~~Cal-~~ California ISO one week prior to initial synchronization with the grid. The project owner shall contact the ~~Western, DSR and Cal-~~ California ISO Outage Coordination Department, Monday through Friday, between the hours of 07:00 and 15:30 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-~~ California 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~~ **transmission facilities**~~. 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 nonconformance 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 electrical portion of the facilities ~~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, **and** related industry standards, and these conditions shall be provided concurrently.

2. An "as built" engineering description of the mechanical, structural, and civil portion of the transmission facilities signed and sealed by the registered engineer in responsible charge or acceptable alternative verification. "As built" drawings of the

electrical, mechanical, structural, and civil portion of the transmission facilities shall be maintained at the power plant and made available, if requested, for CPM audit as set forth in the ~~"~~*Compliance Monitoring Plan*~~"~~.

3. A summary of inspections of the completed transmission facilities, and identification of any nonconforming work and corrective actions taken, signed and sealed by the registered engineer in charge.

~~**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.~~

REFERENCES

California ISO (California Independent System Operator) 1998a. California ISO Tariff Scheduling Protocol posted April 1998, Amendments 1,4,5,6, and 7 incorporated.

California ISO (California Independent System Operator) 1998b. California ISO Dispatch Protocol posted April 1998.

California ISO (California Independent System Operator) 2002a. California ISO Planning Standards, February 7, 2002.

California ISO (California Independent System Operator) 2007a. California ISO, FERC Electric Tariff, First Replacement Vol. No. 1, March, 2007.

California ISO (California Independent System Operator) 2009a, Large Generator Interconnection Procedures.

California ISO/FERC Electric Tariff 2010a. Large generator Interconnection Procedures (LGIP) and LGIA for any large gen interconnection.

BEP II 2009a: Caithness Blythe II, LLC (Caithness): Petition for Amendment of the BEP II project (02-AFC-1C), submitted in October, 2009.

BEP II 2010a: Caithness and Galati/Blek, LLP: Blythe II Amendment Petition, Data Response set #1, submitted on September 14, 2010.

BEP II 2010b: Caithness and Galati/Blek: Blythe II Amendment Petition: System Impact (Planning) Study Report performed by SCE and the May 17, 2006 letter of CA ISO to SCE. Submitted by Caithness on September 14, 2010.

BEP II 2010c: Caithness and Galati/Blek: Blythe II Amendment Petition: Facilities Study Report performed by SCE. Submitted by Caithness on September 14, 2010.

BEP II 2010d: Caithness: Blythe II Amendment Petition: BEP II Expansion Feasibility Study Report performed by CA ISO and SCE. Submitted by Caithness on September 14, 2010.

BEP II 2010e: Caithness and Galati/Blek, LLP: Blythe II Amendment Petition, Data Response set #2, submitted on October 13, 2010.

BEP II 2011a: Caithness and Galati/Blek, LLP: Blythe II Amendment Petition, Data Response set #3, submitted to CEC in October, 2011.

BEP II 2011b: Caithness and Galati/Blek, LLP: Blythe II Amendment Petition: Petition for 5 yr. extension of the construction deadline of the BEP II for 5 years. Submitted to CEC on October 12, 2011.

BEP II 2011c: Caithness and Galati/Blek, LLP: Blythe II Amendment Petition: Declaration of Robert Looper, Senior Vice President, Caithness. Submitted to CEC on Nov. 8, 2011.

BEP II 2011d: Caithness and Galati/Blek, LLP: Blythe II Amendment Petition: Response to CEC staff Counsel's analysis about extension of deadline for commencement of construction of the BEP II. Submitted to CEC on Dec. 2, 2011.

CEC 2005a: California Energy Commission: Blythe II Application for Certification, dated February, 2002. Submitted to CEC/Docket Unit on February 19, 2002.

CEC 2010a: California Energy Commission: Blythe II Amendment Petition: Data Request set #1, submitted on May 13, 2010.

CEC 2011a: California Energy Commission: Blythe II Amendment Petition: Data Request set #2, submitted on May 19, 2011.

CEC 2011b: California Energy Commission: Blythe II Amendment Petition: CEC Staff Counsel's analysis and Recommendation regarding requested extension of deadline for commencement of construction of the BEP II. Submitted on November14, 2011.

NERC (North American Electric Reliability Corporation):2005-10. NERC Reliability Standards, 2005-10.

WECC (Western Electric Coordinating Council) 2008. WECC Regional System Performance Criteria, 2008.

DEFINITION OF TERMS

ACSR	Aluminum cable steel reinforced.
AAC	All Aluminum conductor.
ACSS	Aluminum conductor steel-supported.
Ampacity	Current-carrying capacity, expressed in amperes, of a conductor at specified ambient conditions, at which damage to the conductor is nonexistent or deemed acceptable based on economic, safety, and reliability considerations.
Ampere (A)	The unit of current flowing in a conductor.
Kiloampere (kA)	1,000 Amperes
Bundled	Two wires, 18 inches apart.
Bus	Conductors that serve as a common connection for two or more circuits.
Conductor	The part of the transmission line (the wire) that carries the current.
Congestion Management	Congestion management is a scheduling protocol, which provides that dispatched generation and transmission loading (imports) would not violate criteria.
Emergency Overload	See Single Contingency. This is also called an L-1.
Hertz	The unit for System Frequency.
Kcmil or KCM	Thousand circular mil. A unit of the conductor's cross sectional area, when divided by 1,273, the area in square inches is obtained.
Kilovolt (kV)	A unit of potential difference, or voltage, between two conductors of a circuit, or between a conductor and the ground. 1,000 Volts.
Loop	An electrical cul de sac. A transmission configuration that interrupts an existing circuit, diverts it to another connection and returns it back to the interrupted circuit, thus forming a loop or cul de sac.

MVAR or Megavars	Megavolt Ampere-Reactive. One million Volt-Ampere-Reactive. Reactive power is generally associated with the reactive nature of motor loads that must be fed by generation units in the system.
Megavolt Ampere (MVA)	A unit of apparent power, equals the product of the line voltage in kilovolts, current in amperes, the square root of 3, and divided by 1000.
Megawatt (MW)	A unit of power equivalent to 1,341 horsepower.
Normal Operation/ Normal Overload	When all customers receive the power they are entitled to without interruption and at steady voltage, and no element of the transmission system is loaded beyond its continuous rating.
N-1 Condition	See Single Contingency.
Outlet	Transmission facilities (circuit, transformer, circuit breaker, etc.) linking generation facilities to the main grid.
Power Flow Analysis	A power flow analysis is a forward looking computer simulation of essentially all generation and transmission system facilities that identifies overloaded circuits, transformers and other equipment and system voltage levels.
Reactive Power	Reactive power is generally associated with the reactive nature of inductive loads like motor loads that must be fed by generation units in the system. An adequate supply of reactive power is required to maintain voltage levels in the system.
Remedial Action Scheme (RAS)	A remedial action scheme is an automatic control provision, which, for instance, would trip a selected generating unit upon a circuit overload.
SSAC	Steel Supported Aluminum Conductor.
SF6	Sulfur hexafluoride is an insulating medium.
Single Contingency	Also known as emergency or N-1 condition, occurs when one major transmission element (circuit, transformer, circuit breaker, etc.) or one generator is out of service.
Solid Dielectric Cable	Copper or aluminum conductors that are insulated by solid polyethylene type insulation and covered by a metallic shield and outer polyethylene jacket.

SVC	Static VAR Compensator: An equipment made of Capacitors and Reactors with electronic controls for producing and controlling Reactive Power in the Power System.
Switchyard	A power plant switchyard (switchyard) is an integral part of a power plant and is used as an outlet for one or more electric generators.
Thermal rating	See ampacity.
TSE	Transmission System Engineering.
TRV	Transient Recovery Voltage
Tap	A transmission configuration creating an interconnection through a sort single circuit to a small or medium sized load or a generator. The new single circuit line is inserted into an existing circuit by utilizing breakers at existing terminals of the circuit, rather than installing breakers at the interconnection in a new switchyard.
Undercrossing	A transmission configuration where a transmission line crosses below the conductors of another transmission line, generally at 90 degrees.
Underbuild	A transmission or distribution configuration where a transmission or distribution circuit is attached to a transmission tower or pole below (under) the principle transmission line conductors.
VAR	Voltage Ampere Reactive, a measure for Reactive power in the power system.

BLYTHE ENERGY PROJECT, PHASE II (02-AFC-1C) PETITION TO AMEND ENERGY COMMISSION DECISION WATER RESOURCES

Prepared by Casey Weaver

INTRODUCTION AND SUMMARY OF CONCLUSIONS

On October 23, 2009, Caithness Blythe II, LLC (Caithness) filed a petition with the California Energy Commission requesting modification of the approved BEP II project. A modification to the petition was filed on January 4, 2010. Supplemental water information was filed on February 16, 2010. On March 6, 2012, supplemental water information was received.

To ensure that the project's water consumption is consistent with the original analysis and likely operating scenarios, staff proposes the addition of new conditions of certification **WATER RES - 4** to **- 7**. These new conditions limit project water consumption to 2,800 Acre Feet per Year (AFY) and require reporting to insure project compliance.

ANALYSIS

The Final Decision for the Blythe Energy Project II discussed project water use as 3,300 acre feet of water per year. This allocation was based on a base load 520 MW facility operating at a 95 percent capacity factor (c.f.) throughout the year (8,322 hours). Subsequent to the final decision, the project owner has petitioned to amend the project to a Siemens Flex Plant 30, designed to compete in the high renewable market at about a 61 percent c.f. throughout the year (5,385 hours). This proposed change in operation is due to the project owner's claim that the project failed to win a power purchase agreement as a base load plant, but is expected to be competitive in the next solicitation as a mid-merit, dispatchable plant, which will likely generate electricity 5 days per week at 16 hours per day for 8 months of the year, and 7 days per week at 24 hours per day during the 4 "summer" months (June through September) of the year (BEP II 2012a).

The Flex Plant equipment described in the amendment is larger in size (570 MW versus 520 MW) than the project approved in the Final Decision. Even though the proposed amended project would have a higher nominal capacity and would have potentially higher instantaneous water use, the reduction in operation would use less water annually than that discussed in the Final Decision. The project owner estimates the amended project would consume 2,282 AFY. Should the operation of the proposed Flex Plant increase beyond the estimated 61 percent c.f., water use would be above that estimated in the amendment. For example, if the "summer" peak was to start in May or extend into October, water use might increase to 2,702 AFY. Additionally, if the proposed plant outage in February does not occur, water use might be close to 2,800 AFY in a theoretical worst case year. Therefore, to ensure that the project's water consumption will not significantly impact plant operability and dispatchability, staff recommends that the project's water consumption be limited to not more than 2,800 AFY to allow for a margin above the expected levels of 2,281 AFY. Staff proposes additional of conditions of certification **WATER RES-4** to **-7**, shown below. The conditions limit project water use and require reporting to insure project compliance.

While the amended project is expected to use less water annually under the currently expected operating scenario, at times it will require delivery of water at a slightly higher rate than that analyzed in the approved project. For the approved project, the average water demand was calculated to be 2,146 gallons per minute (gpm) per actual operating hour. For the proposed project, the average water demand was calculated to be 2,300 gallons per minute (gpm) per actual operating hour. This change is an increase in water demand of 154 gallons per minute per actual operating hour. This minimal change in operational water demand is not considered to be significantly different from that analyzed in the Final Decision. Should impacts to groundwater occur from this additional demand, mitigation for those impacts is defined in Condition of Certification **WATER RES - 3** of the Final Decision.

CONCLUSIONS AND RECOMMENDATIONS

Staff has reviewed the petition and supplemental information to assess if the proposed project modifications would result in environmental impacts beyond those addressed in the Final Decision of the approved project and remain in compliance with applicable laws, ordinances, regulations and standards (LORS). Based on this review, staff has determined that the amended project, with adoption of staff's proposed additional conditions of certification, would not create environmental impacts beyond those addressed in the Final Decision of the approved project and would be consistent with the LORS identified in the Energy Commission Decision.

To limit project water consumption and insure project compliance, Staff proposes the adoption of new Conditions of Certification **WATER RES-4**, **WATER RES-5**, **WATER RES-6** and **WATER RES-7**.

WATER RES-4 is necessary because staff analysis determined that annual consumption of 2,800 AFY would be adequate to operate the project with an allowance for unusual years. The imposed limit reduces the limit from the original Commission Decision and helps to ensure that only water necessary to operate the project will be used. **WATER RES-5** is necessary to ensure that water meters will accurately measure the power plant's water use. **WATER RES-6** is necessary to ensure that the project owner is not using water in quantities that violate other conditions of certification. **WATER RES-7** is necessary to demonstrate that the actual volume of water used during the year remains in compliance with the conditions of certification.

PROPOSED NEW CONDITIONS OF CERTIFICATION

Below is a list of the new proposed Water Resource Conditions of Certification. **Underline and bold** is used for new language.

WATER RES - 4: BEP II's annual use of water shall not exceed a maximum of 2,800 acre-feet per year.

Verification: In compliance with WATER RES-2, the project owner shall record and provide to the CPM water use reports that demonstrate annual water consumption does not exceed 2,800 AFY.

WATER RES - 5: The project owner shall service, test and calibrate the water meters in accordance with the manufacturer's specifications.

Verification: When the metering devices are serviced, tested and calibrated, the project owner shall provide to the CPM a report summarizing these activities in the next Annual Compliance Report (ACR).

WATER RES - 6: For the first year of operation the project owner shall monitor, record and submit to the CPM the total water used on a monthly basis.

Verification: On a monthly basis for the first year of operation, the project owner shall provide to the CPM a Monthly Water Use Summary that states the quantity of water used daily during that month.

WATER RES - 7: The project owner shall prepare an annual Water Use Summary, which will include the monthly range and monthly average of water usage in gallons per day, and total water used by the project on a monthly and annual basis in acre-feet. For calculating the annual water use, the term "year" will correspond to the date established for the Annual Compliance Report (ACR) submittal.

For years subsequent to the first year, the annual Water Use Summary shall in addition to the information described above, also include the yearly range and yearly average water use by the project. The annual Water Use Summary shall be submitted to the CPM as part of the ACR.

Verification: The project owner shall provide a Water Use Summary that sets forth the information required in the condition above in the ACR. All prior annual water use, including yearly range and yearly average, shall be reported in subsequent ACRs.

REFERENCES

BEP II 2009a: Caithness Blythe II, LLC (Caithness). Petition for Amendment of the BEP II project (02-AFC-1C), submitted in October, 2009.

BEP II 2010a: Caithness Blythe II, LLC (Caithness). Modification to Petition to Amend the BEP II project (02-AFC-1C), submitted January 4, 2010.

BEPII 2010b: Caithness Blythe II, LLC (Caithness). Supplement #1 to Petition to Amend the BEP II project (02-AFC-1C) – Water, submitted February 16, 2010.

BEP II 2012a: Caithness Blythe II, LLC (Caithness). Supplement #4 to Petition to Amend the BEP II project (02-AFC-1C) – Water. Email from Scott Galati to Matthew Layton on March 6, 2012 at 1:44 p.m.

CEC 2005a: California Energy Commission (CEC). Blythe Energy Project, Phase II Final Staff Assessment, filed April, 2005.

CEC 2005b: California Energy Commission (CEC). Blythe Energy Project, Phase II Supplement to the Final Staff Assessment, filed June, 2005.

CEC 2005c: California Energy Commission (CEC). Blythe Energy Project, Phase II Commission Decision, filed December, 2005.

BLYTHE ENERGY PROJECT, PHASE II (02-AFC-1C)
PETITION TO AMEND COMMISSION DECISION
WORKER SAFETY

Prepared by Alvin Greenberg, Ph.D.

INTRODUCTION AND SUMMARY OF CONCLUSIONS

On October 23, 2009, Caithness Blythe II, LLC (Caithness) filed a petition with the California Energy Commission requesting to modify the BEP II. A modification to the petition was filed on January 4, 2010. Supplement water information was filed on February 16, 2010, supplemental Transmission System Engineering (TSE) information was filed on April 23, 2010 and on October 4, 2011 supplemental information was filed for Traffic and Transportation and TSE.

The petition to amend seeks to allow replacement of the permitted turbines with the latest technology combustion turbines available and incorporate fast-start technology. Furthermore, the project owner has proposed in a January 4, 2010 modification to the amendment to not use inlet chillers on the new turbines, and thus not use anhydrous ammonia at the project.

The project owner has requested that Condition of Certification **WORKER SAFETY-3** be eliminated in its entirety. **WORKER SAFETY-3** addresses worker training regarding the presence of anhydrous ammonia in the refrigeration system which is part of the inlet chiller. Since the new turbines will not use inlet chillers, anhydrous ammonia is longer proposed to be used on the site. Staff therefore concludes that it is no longer necessary to require that workers be trained to the level of Hazmat Technician in order to assist in responding to an accidental release of anhydrous ammonia. Aqueous ammonia continues to be used in the SCR system and existing conditions of certification already address the prevention of releases, containment if a release should occur, and emergency response should that be necessary.

In the past two years, it has come to staff's attention that Valley Fever (Coccidioidomycosis) can be contracted when desert soils are disturbed by excavation, grading, and trenching and that precautions can and should be taken by the project owner to protect workers during soil disturbance activities. Staff proposes a new Condition of Certification, **WORKER SAFETY- 6,** requiring the implementation of dust control measures to address this concern.

PROJECT LOCATION AND DESCRIPTION

The BEP II is licensed as a nominally rated 520-megawatt (MW) combined-cycle facility with a maximum output of 538 MWs. The project was certified by the Energy Commission on December 14, 2005.

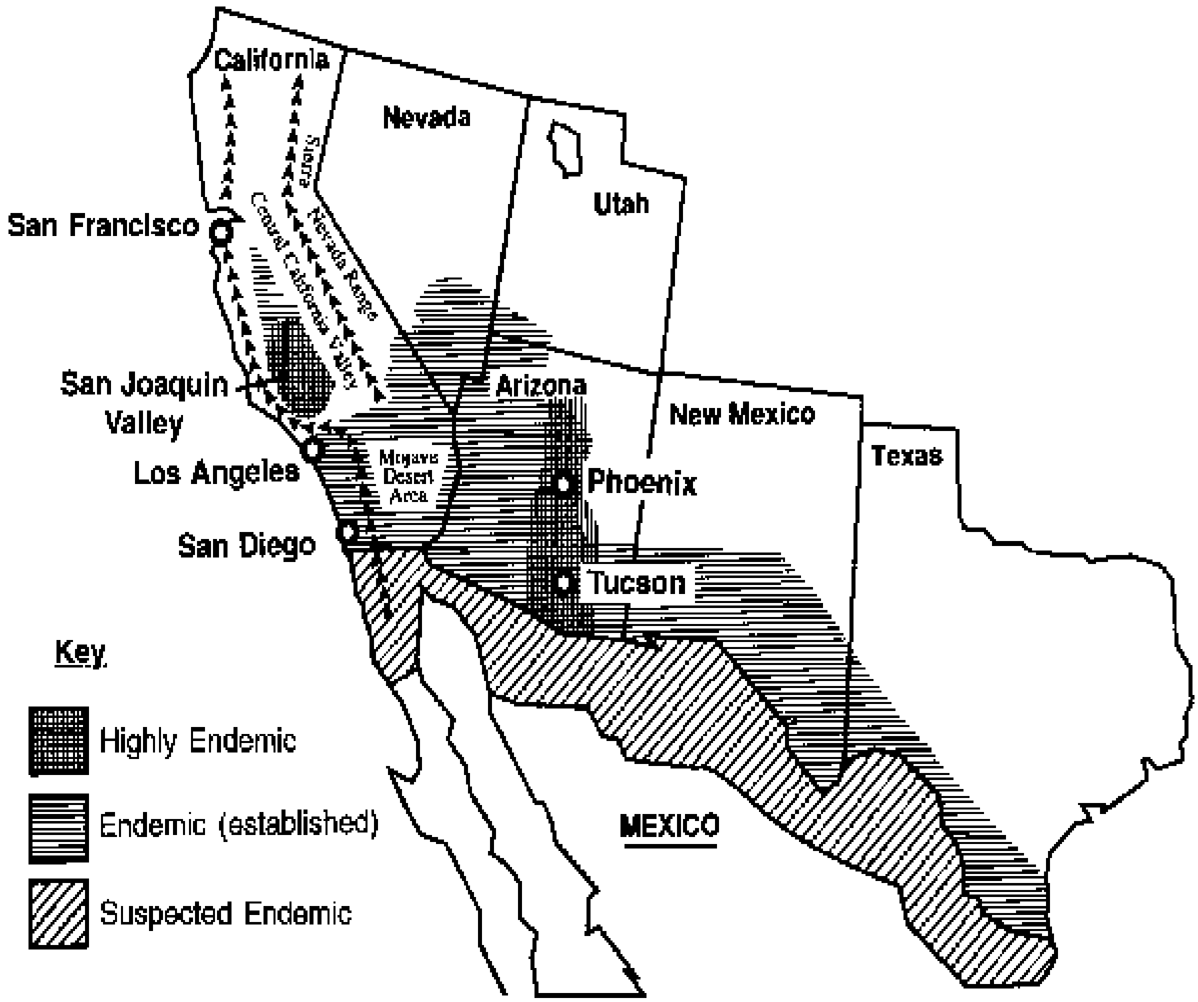
The Project is located within the City of Blythe, approximately five miles west of the center of the City. The BEP II site boundary is located on a 76 acre site immediately adjacent to the operational Blythe Energy Project (BEP I), owned by Blythe Energy, LLC and operated by NextEra Energy Operating Services, LLC.

ANALYSIS

The project owner has requested that Condition of Certification **WORKER SAFETY-3** be eliminated in its entirety. **WORKER SAFETY-3** addresses worker training regarding the presence of anhydrous ammonia in the refrigeration system which is part of the inlet chiller. Since the new turbines will not use inlet chillers, anhydrous ammonia is longer proposed to be used on the site. Staff therefore concludes that it is no longer necessary to require that workers be trained to the level of Hazmat Technician in order to assist in responding to an accidental release of anhydrous ammonia. Aqueous ammonia continues to be used in the SCR system and existing conditions of certification already address the prevention of releases, containment if a release should occur, and emergency response should that be necessary.

In regards to Valley Fever, Coccidioidomycosis or "Valley Fever" (VF) is primarily encountered in southwestern states, particularly in Arizona and California. It is caused by inhaling the spores of the fungus Coccidioides immitis, which are released from the soil during soil disturbance (e.g., during construction activities) or wind erosion. The disease usually affects the lungs and can have potentially severe consequences, especially in at-risk individuals such as the elderly, pregnant women, and people with compromised immune systems. Trenching, excavation, and construction workers are often the most exposed population. Treatment usually includes rest and antifungal medications. No effective vaccine currently exists for Valley Fever. VF is endemic to the San Joaquin Valley in California, which presumably gave this disease its common name. In California, the highest VF rates are recorded in Kern, Kings, and Tulare Counties, followed by Fresno and San Luis Obispo Counties. LA County, San Diego County, San Bernardino County, and Riverside County also have reported VF cases although much fewer. **WORKER SAFETY Figure 1** shows the geographic distribution of Coccidioidomycosis.

WORKER SAFETY Figure 1
Geographic Distribution of Coccidioidomycosis*



*Source: CDC 2006, Figure 2

A 2004 CDC report found that the number of reported cases of coccidioidomycosis in the US increased by 32 percent during 2003-2004, with the majority of these cases occurring in California and Arizona. The report attributed these increases to changes in land use, demographics, and climate in endemic areas, although certain cases might be attributable to increased physician awareness and testing (CDC 2006). According to the CDC Morbidity and Mortality Weekly Report of February 2009, incidences of valley fever have increased steadily in Arizona and California in the past decade. Cases of coccidioidomycosis averaged about 2.5 per 100,000 population annually from 1995 to 2000 and increased to 8.0 per 100,000 population between 2000 and 2006 (incident rates tripled). In 2007 there was a slight drop in cases, but the rate was still the highest it has been since 1995. The report identified Kern County as having the highest incidence rates (150.0 cases per 100,000 population), and non-Hispanic blacks having the highest hospitalization rates (7.5 per 100,000 population). In addition, between the years 2000 and 2006, the number of valley fever related hospitalizations climbed from 1.8 to 4.3 per 100,000 population (611 cases in 2000 to 1,587 cases in 2006) and then decreased to 1,368 cases in 2007 (3.6 per 100,000 population). Overall in California, during 2000-2007, a total of 752 (8.7 percent) of the 8,657 persons hospitalized for coccidioidomycosis died (CDC 2009).

A 2007 study published in the Emerging Infectious Diseases journal of the Center for Disease Control and Prevention (CDC), found the frequency of hospitalization for coccidioidomycosis in the entire state of California to be 3.7 per 100,000 residents per year for the period between 1997 and 2002. There were 417 deaths from VF in California in those years, resulting in a mortality rate of 2.1 per 1 million California residents annually.

Riverside County has approximately 50 cases of VF per year (population is roughly 2 million) while nearby San Diego County has about 120 cases per year (population roughly 3 million). In comparison, an average of over 1,000 cases have been reported annually in Kern County during the last five years. Cases of VF in Riverside County have remained steady in the past several years, fluctuating only slightly between 48 and 55 cases per year. Nine deaths related to VF have been reported in Riverside County between 2005 and 2008 (Williams 2009). A rate of 50 cases per year per 2,000,000 persons corresponds to a risk of about 25 in 1 million and a rate of 2.5 cases per 100,000 persons, which is lower than the average rate for the entire state of California (~3.6 cases per 100,000 residents). Data received from the Riverside County Department of Public Health indicates that the crude VF rate in Riverside County between 1999 and 2006 has been even lower, about 15 per 100,000 residents. The region in which the BEP II project would be located has recorded 5 or fewer cases between 1999 and 2006 (RCDPH 2007). **WORKER SAFETY Table 1** shows the Valley Fever rates in Riverside County.

WORKER SAFETY Table 1
Valley Fever Rates in Riverside County

County of Riverside - Reported Cases: Coccidioidomycosis (Valley Fever) Years 1999-2006, by Zip Code of Residence[1]			
Zip Code	**PO Name**	**8-Year Total**	**8-Year Estimated Crude Aggregate Rate (per 10,000)**
92236	Coachella	5	1.7
92225	Blythe	5	2.8
92883	Corona	5	2.6
92591	Temecula	5	1.5
92201	Indio	6	1.0
92505	Riverside	6	1.4
92544	Hemet	7	1.6
92530	Lake Elsinore	7	1.4
92506	Riverside	7	1.5
92879	Corona	8	1.6
92507	Riverside	10	1.9
92583	San Jacinto	10	4.0
92570	Perris	11	2.5
92220	Banning	12	3.8
92586	Sun City	12	6.2
92509	Riverside	13	1.8
92504	Riverside	21	4.0
92503	Riverside	32	4.1
TOTAL	ALL COUNTY	280	1.5

Notes:

1 - Only zip codes for which more than 4 cases were recorded during the 8-year period are included
Source: DHS: AVSS CMR reporting

Compiled: Riverside County Department of Public Health, Epidemiology and Program Evaluation, Kevin Meconis, Epidemiologist, 11/19/2007

A 1996 paper that tried to explain the sudden increase in Coccidioidomycosis cases that began in the early 1990’s found that the San Joaquin Valley in California has the largest population of C. immitis, which is found to be distributed unevenly in the soil and seems to be concentrated around animal burrows and ancient Indian burial sites. It is usually found 4 to 12 inches below the surface of the soil. The paper also reported that incidences of coccidioidomycosis vary with the seasons; with highest rates in late summer and early fall when the soil is dry and the crops are harvested. Dust storms are frequently followed by outbreaks of coccidioidomycosis (Kirkland 1996). A modeling attempt to establish the relationship between fluctuations in VF incident rates and weather conditions in Kern County found that there is only a weak connection between weather and VF cases (weather patterns correlate with up to 4 percent of outbreaks).

The study concluded that the factors that cause fluctuations in VF cases are not weather-related but rather biological and anthropogenic (i.e. human activities, primarily construction on previously undisturbed soil) (Talamantes 2007).

During correspondence with Dr. Michael MacLean of the Kings County Health Department, he noted that according to his experience and of those who study VF, it is very hard to find the fungus in soil that was previously farmed and irrigated, which greatly reduces the risk of infection resulting from disturbance of farmed lands. This does not apply to previously undisturbed lands where excavation, grading, and construction may correlate with increases in VF cases. Dr. MacLean feels that with the current state of knowledge, we can only speculate on the causes and trends influencing VF cases and he does not feel that construction activities are necessarily the cause of VF outbreaks (KCEHS 2009).

Valley Fever is spread through the air. If soil containing the fungus is disturbed by construction, natural disasters, or wind, the fungal spores get into the air where people can breathe in the spores. The disease is not spread from person to person. Occupational or recreational exposure to dust is an important consideration. Agricultural workers, construction workers, or others (such as archeologists) who dig in the soil in the disease-endemic area of the Central Valley are at the highest risk for the disease (CDC 2006; CDHS 2010). The risk for disseminated coccidioidomycosis is much higher among some ethnic groups, particularly African-Americans and Filipinos. In these ethnic groups, the risk for disseminated coccidioidomycosis is tenfold that of the general population (CDC 2006).

Given the available scientific and medical literature on Valley Fever, it is difficult for staff to assess the potential for VF to impact workers during construction and operation of the proposed BEP II project with a reasonable degree of certainty. To minimize potential exposure of workers and also the public to coccidioidomycosis during soil excavation and grading, extensive wetting of the soil prior to and during construction activities should be employed and dust masks should be worn at certain times during these activities. Towards that, staff proposes new Condition of Certification **WORKER SAFETY-6** which would require that the implementation of dust control measures including implementing methods equivalent to the requirements of Rule 402 of the Kern County Air Pollution Control District (as amended Nov. 3, 2004). Staff has found that the Kern County Rule is the most efficacious rule among several different air district rules reviewed for the control of airborne dust during construction activities.

CONCLUSIONS AND RECOMMENDATIONS

Staff has reviewed the petition and supplemental information for potential environmental effects and consistency with applicable LORS. Based on this review, staff determined that the amendment, with staff's proposed changes, would be consistent with the LORS identified in the Energy Commission Decision. Staff proposes the deletion of Condition of Certification **WORKER SAFETY-3** and the addition of **WORKER SARETY-6**, as shown below.

PROPOSED MODIFICATIONS TO CONDITIONS OF CERTIFICATION

~~Strikethrough~~ is used to indicate deleted language and **<u>underline and bold</u>** is used for new language.

~~**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.~~

<u>WORKER SAFETY-6 The project owner shall develop and implement an enhanced Dust Control Plan that includes the requirements described in AQ-SC3 and additionally requires:</u>

- **i. <u>site worker use of dust masks (NIOSH N-95 or better) whenever visible dust is present;</u>**
- **ii. <u>implementation of methods equivalent to Rule 402 of the Kern County Air Pollution Control District (as amended Nov. 3, 2004); and</u>**
- **iii. <u>implementation of enhanced dust control methods (increased frequency of watering, use of dust suppression chemicals, etc. consistent with AQ-SC4) immediately whenever visible dust comes from or onto the site or when PM10 measurements obtained when implementing ii (above) exceed 50 μg/m^3.</u>**

<u>Verification: At least 60 days prior to the commencement of site mobilization, the enhanced Dust Control Plan shall be provided to the CPM for review and approval.</u>

REFERENCES

BEPII 2009: Blythe Energy Center, Phase II (02-AFC-1C). Air Modeling Files. Received August, 2009.

BEPII 2009: Blythe Energy Center, Phase II (02-AFC-1C). Petition to Amend. Received October 23, 2009.

BEPII 2010: Blythe Energy Center, Phase II (02-AFC-1C). Modification to Petition to Amend. Received January 4, 2010.

BEPII 2010: Blythe Energy Center, Phase II (02-AFC-1C). Supplement to Petition to Amend. Received February 16, 2010.

CEC 2005: California Energy Commission, Commission Decision, Blythe Energy Center, Phase II, December 14, 2005.